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4.6.0 Steam Generator Tube Rupture

Learning Objectives:

1. Discuss why operator intervention is necessary to limit or prevent radiological releases during a steam generator tube rupture (SGTR) event.
2. Discuss the primary-side and secondary-side indications of an SGTR in the control room.
3. Discuss how the affected generator may be identified either prior to or following the reactor/turbine trip.
4. List the initial actions taken by the operator once the affected steam generator has been identified.
5. Discuss the actions required to stop the primary-to-secondary leakage.
6. Discuss the problems associated with the following:
   a. Secondary-to-primary leakage
   b. Steam generator overfill.
7. List the principal systems/components affected by a loss of offsite power (LOOP).
8. Discuss how plant cooldown and pressure control are accomplished with an SGTR and LOOP.
9. Discuss what affect the following events had on the SGTR transient at the Ginna plant:
   a. Tripping of the reactor coolant pumps
   b. Failure of pressurizer power-operated relief valve (PORV)
   c. Automatic operation of letdown valves
   d. Pressurizer relief tank failure
   e. Steam generator safety valve failure.

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4.6.1 Introduction

Of all the major accidents that have actually occurred at operating PWRs, steam generator tube failures have occurred most frequently. The nuclear industry has implemented many programs to reduce the incidents of tube failures, such as secondary side inspections, improved steam generator designs and water chemistry control, and more reliable eddy current tube inspection techniques. Nevertheless, a steam generator tube failure may remain one of the more likely accidents. Such accidents provide a direct release path for contaminated primary coolant to the environment via the secondary side safety and relief valves. Accumulation of water in the SG secondary side can also lead to an overfill condition which can severely aggravate the radiological consequences and increases the likelihood of subsequent failures.

Unlike other loss of coolant accidents (LOCA), a steam generator tube failure demands substantial operator involvement early in the event. Timely operator intervention is necessary to prevent steam generator overfill and limit the radiological releases.

The following sections describe the plant response to an actual and a postulated steam generator tube failure. A steam generator tube rupture event begins as a breach of the primary coolant barrier between the reactor coolant system and secondary side of the steam generator, i.e., the steam generator tube, Figure 4.6-1. Although this relatively thin barrier is designed with substantial safety margin to preclude bursting even when subjected to full primary system pressure, the harsh secondary side environment may attack the steam generator tubes resulting in excessive tube wall thinning or cracking over time. Although improved secondary side chemistry has greatly reduced the frequency of tube failures attributed to chemical corrosion, foreign objects in the steam generator secondary have resulted in relatively rapid tube degradation and eventually tube failure (Prairie Island [1979] and Ginna [1982]). Even more recently (North Anna [1987]), tube failure was caused by flow-induced fatigue cracking.

4.6.2 Expected Plant Response to SGTR Event with Timely Operator Intervention

This section contains a description of the expected plant response to a postulated steam generator tube rupture accident and the actions, both operator initiated and automatic, which may occur during recovery. System response and recovery actions with offsite power available, section 4.6.2.1, and the effects of a loss of offsite power coincident with turbine trip, section 4.6.2.2, are discussed. As previously noted, the trends described are only representative since variations in manual actions or operable equipment as well as rupture size and specific plant design will result in slightly different system conditions. In the transient plots presented, a tube failure is to be the initiating event and it occurs when the plant is at full power.

4.6.2.1 SGTR Transient: Offsite Power Available

Since the primary system pressure (nominally 2235 psig) is initially much greater than the steam generator pressures (nominally 1000 psig) reactor coolant flows from the primary into the secondary side of the affected steam generator. In response to this loss of reactor coolant, pressurizer level and pressure decrease at a rate which is dependent upon the size and number of failed tubes, as shown in Figure 4.6-2. The Pressure decreases as the steam bubble in the pressurizer expands. Normally, charging flow will automatically increase and pressurizer heaters will energize in an effort to stabilize pressure and level. However, if leakage exceeds the capacity of the chemical and volume control system (CVCS), reactor coolant inventory will continue to decrease and eventually lead to an automatic reactor trip signal. If turbine load is not reduced, reactor trip will most likely occur on overtemperature ΔT. For the expected case, however, turbine load will be decreased either automatically or manually so that reactor trip will occur on low pressurizer pressure. Normal letdown flow would isolate and pressurizer heaters would turn off on low pressurizer level.

On the secondary side, leakage of contaminated primary coolant will increase the activity of the secondary coolant resulting in high radiation indications from the air ejector radiation monitor and blow down line radiation monitors. Although these alarms may lag indications of a loss of reactor coolant, depending on the transport time to the radiation monitors, they have sounded nearly simultaneously with pressurizer low level indications during past tube failure events and generally provide the earliest diagnosis of a steam generator tube rupture. As primary coolant accumulates in the affected steam generator, normal feedwater flow is automatically reduced to compensate for high steam generator level. Consequently, a mismatch between steam flow and feedwater flow to the affected steam generator may be observed. This potentially provided early confirmation of a tube failure event and also identifies the affected steam generators. However, such a mismatch may not be noticeable for smaller tube failures because of the relatively large normal feedwater/steam flow rates. The water level in the affected steam generators may not be significantly greater than that of the intact steam generators prior to reactor trip as the normal feedwater control system automatically compensates for changes in steam flow rate and steam generator level due to primary-to-secondary leakage.

The time between initial tube failure and reactor trip also depends on the leak rate. In most cases sufficient time will be available (greater than three minutes) for the operator to perform a limited number of actions to either prevent or prepare for reactor trip. Such actions are likely to include starting additional charging pumps, energizing pressurizer heaters if not done automatically, reducing the load on the turbine, and possibly manually tripping the reactor. These actions, with the exception of manual reactor trip, will tend to delay an automatic trip signal. In addition, these actions can have a significant effect on the system response following reactor trip which may impact the longer term recovery. For example, as turbine run back proceeds, the mismatch between core power and turbine load causes the average coolant temperature (T_{avg}) to increase until the rod control and steam dump system actuate to restore programmed T_{avg}. A period of time may exist when T_{avg} is greater than nominal full power conditions. If reactor trip occurs during this time, the resulting cooldown of the primary system is larger when the steam dump system actuates to establish no-load conditions. The combination of a delayed reactor trip and greater shrinkage of reactor coolant may result in a significantly lower minimum RCS pressure following reactor trip. In that case RCP trip criteria may be met. This may also result in a greater steam generator inventory before recovery actions are initiated which would reduce the time available to steam generator overfill.

Following reactor trip, core power rapidly decreases to decay heat levels, steam flow to the turbine is terminated, and the steam dump system actuates to establish no-load coolant temperatures in the primary system (Figure 4.6-3). Shortly thereafter, the normal feedwater control system increases feedwater flow to compensate for shrinkage in steam generator level due to reduced steam flow. RCS pressure decreases more rapidly as energy transfer to the secondary shrinks the reactor coolant and tube rupture flow continues to deplete primary inventory. This decrease in RCS pressure results in a low pressurizer pressure SI signal soon after reactor trip. Normal feedwater flow is automatically isolated on the SI signal which also actuates the auxiliary feedwater (AFW) system to deliver flow to all steam generators. For some plants, low water level is a combination of the steam generators coincident with the SI signal is required to actuate some components of the AFW system. However, since level drops below the narrow range on reactor trip from full power (Figure 4.6-4) the AFW system will also actuate on the SI signal for plants with this logic. If trip occurs at a lower power for these plants, AFW flow may not be initiated until sometime after the SI signal occurs. Eventually, manual action is required to decrease auxiliary feedwater flow to maintain the steam generator water level on the narrow range span. The expected sequence of automatic actions following reactor trip is presented in Table 4.6-1.

Secondary-side pressure will increase rapidly after reactor trip as automatic isolation of the turbine momentarily stops steam flow from the steam generators (Figure 4.6-4). Normally, automatic steam dump to the condenser will actuate to dissipate energy transferred from the primary, thereby limiting the secondary pressure increase. Since the intact and ruptured steam generators are connected via the main steam header, no significant difference in pressures will be evident at this time.

Initially, SI flow and AFW flow will absorb decay heat and decrease the reactor coolant temperature below no-load until AFW flow is manually throttled to maintain steam generator level in the narrow range. Steam flow should stop when the reactor coolant temperature decreases below no-load temperature (Figure 4.6-4) and the steam generator pressures may slowly decrease as the cold AFW flow condenses steam. At low decay heat levels or for multiple tube failures the reactor coolant temperature may continue to decrease due to SI flow even after AFW flow is throttled.

Pressurizer level decreases more rapidly following reactor trip as the reactor coolant shrinks during the post-trip cooldown and primary-to-secondary leakage continues to deplete coolant inventory. Although the minimum pressurizer level is dependent upon a number of parameters, including initial pressurizer level, initial power level, the size of the tube failure, operation of pressurizer heaters, and pre-trip operator actions, it is likely that level will be nearly off-scale low when SI is actuated. With SI actuated, the primary system will tend toward an equilibrium condition where break flow and coolant shrinkage are matched by SI flow (Figure 4.6-5). If break flow and shrinkage are initially greater than SI flow, pressurizer level and pressure will continue to decrease until quasi-equilibrium conditions are reached. In some cases, such a multiple tube failures or reduced SI capacity, RCS pressure may momentarily decrease to saturation until SI flow and AFW flow cool the primary system below the saturation temperature of the steam generators. Conversely, if SI flow exceeds primary-to-secondary leakage and coolant shrinkage, the pressurizer level and pressure will increase until equilibrium is achieved. The equilibrium RCS pressure depends on the size of the tube failures, capacity of the SI system, and cooldown rate of the primary. However, since leakage from the RCS is a function of both pressure and temperature, RCS pressure may continue to slowly decrease until reactor coolant temperatures are stabilized.

For high pressure SI plants, the pressurizer may refill to a relatively high level prior to operator intervention if the tube failure is small. However, in the more likely case, pressurizer level will return on span and will stabilize at a value significantly below nominal level, as shown in Figure 4.6-2. A point of confusion often noted occurs during simulation of a steam generator tube failure event where pressurizer level continues to increase toward an overfill condition following actuation of the SI system. While the pressurizer could fill for small tube failures in high pressure SI plants, in some cases this response has been attributed to modelling limitations of the pressurizer. The operator should be aware that although filling of the pressurizer is possible, it is not generally expected. It should also be clear that the reactor coolant temperature trend and operator actions, such as throttling AFW flow, will affect the pressurizer level.

As previously mentioned, the steam generator level may drop out of the narrow range following reactor trip, as shown in Figure 4.6-4. AFW flow will begin to refill the SGs, distributing approximately equal flow to all SGs. Since primary-to-secondary leakage adds additional inventory which accumulates in the ruptured SG, the level will return significantly earlier and will continue to increase more rapidly. This response provides confirmation of a SGTR event and also identifies the affected SG. Although these symptoms will be evident soon after reactor trip for larger tube failures, the SG level response may not be noticeably different or may be masked by non-uniform AFW flows for smaller tube failures in one or more SGs. In that case, high radiation indications may be necessary for positive identification of a ruptured SG. In such instances of smaller tube failures, the break flow would be less and, consequently, more time would be available for recovery prior to filling the affected S/G with water.

Once a tube failure has been identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the affected SGs In addition to minimizing radiological releases, this also reduces the possibility of filling the affected SG with water by (1) minimizing the accumulation of feedwater flow and (2) enabling the operator to establish a pressure differential between the ruptured and intact SGs as a necessary step toward terminating primary-to-secondary leakage. In the analysis results, the operator was assumed to isolate the affected SG when the water level returned into the narrow range (> 15%). With steam flow and feedwater flow terminated, the affected SG pressure will slowly increase as primary-to-secondary leakage compresses the steam bubble in the SG.

High pressure SI plants would also show similar trends. Eventually an SG atmospheric relief valve would lift unless actions to stop leakage into the affected SG are completed.

After isolation of the ruptured SG, the RCS is cooled to less than saturation at the ruptured SG pressure by dumping steam from only the intact SGs. This insures adequate subcooling in the RCS after depressurization to the ruptured SG pressure in subsequent actions. With offsite power available, the normal steam dump system to the condenser provides sufficient capacity to perform this cooldown rapidly, as demonstrated in Figure 4.6-6.

RCS pressure will decrease during this cooldown as shrinkage of the reactor coolant expands the steam bubble in the pressurizer (Figure 4.6-6). For multiple tube failures, RCS pressure (Figure 4.6-7) may decrease to less than the ruptured SG pressure as steam voids, which were generated during initial RCS depressurization, condense. Reverse flow, i.e., secondary-to-primary leakage, during this time would reduce the inventory in the ruptured S/Gs and delay steam generator overfill, as shown in Figure 4.6-7.

When the cooldown is completed SI flow again increases RCS pressure toward an equilibrium value where break flow matches SI flow. Consequently, SI flow must be terminated to stop primary-to-secondary leakage. However, adequate coolant inventory must first be ensured. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after SI flow is stopped. Since leakage from the primary side will continue until RCS and ruptured SG pressures equalize, an excess amount of inventory is required before stopping SI flow. The “excess” amount of inventory required depends upon the RCS pressure and reduces to zero when RCS pressure equals the pressure in the ruptured SG. It is necessary to accommodate the decrease in pressurizer level after SI flow is stopped. To establish sufficient inventory, RCS pressure is decreased by condensing steam in the pressurizer using normal spray. This increases SI flow and reduces break flow, which refills the pressurizer, as illustrated in Figures 4.6-8 and 4.6-9. Note that although the cooldown of the primary side also decreased RCS pressure, the pressurizer did not refill since the net effect reduced coolant volume. Similarly, spraying the pressurizer to decrease RCS pressure concurrently with the primary side cooldown is not as effective in refilling the pressurizer, as shown in Figure 4.6-10.

For multiple tube failures, RCS pressure may decrease below the ruptured steam generator pressure before pressurizer level returns on scale. In that case, reverse flow through the failed tubes will supplement SI flow in refilling the pressurizer. Conversely, for smaller tube failures, pressurizer inventory may stay on scale and additional actions to restore inventory would not be necessary.

Previous actions were designed to establish adequate RCS subcooling, secondary side heat sink, and reactor coolant inventory to ensure SI flow is no longer required. When these actions have been completed, SI flow must be stopped to prevent repressurization of the RCS and to terminate primary-to-secondary leakage. With SI flow stopped, residual break flow will reduce RCS pressure to equilibrium with the ruptured SG, as shown in Figure 4.6-11. RCS temperature, pressurizer level, and affected SG levels will stabilize (Figure 4.6-12) and no further uncontrolled releases of radiological effluent from the ruptured SG will occur. Note that although the level in the affected steam generator may reach the top of the narrow range span, significant volume still exists before the SG fills with water.

4.6.2.2 SGTR Transient: Offsite Power Not Available

The principal systems/components affected by a loss of offsite power are the steam dump system, reactor coolant pumps, and RCS pressure control. The effect of each of these on the system response and recovery is discussed.

The steam dump system is designed to actuate following loss of load or reactor trip to limit the increase in secondary side pressure. Without offsite power available, the steam dump valves, which bypass the turbine to the condenser, will remain closed. Hence, energy transferred from the primary will rapidly increased SG pressures after reactor trip until the atmospheric relief valves lift to dissipate this energy, as shown in Figure 4.6-13. Since the secondary side temperature increase is greater, sensible energy transfer from the primary side following a reactor trip is reduced. Consequently, RCS pressure decreases more slowly, as illustrated in Figure 4.6-14, so that SI actuation and all attendant automatic actions are delayed. A typical sequence of events without offsite power available is also presented in Table 4.6-1.

RCPs trip on a loss of offsite power and a gradual transition to natural circulation flow ensues. The cold leg temperature trends toward the SG temperature as the fluid residence time in the tube region increases. Initially, the core ΔT decreases as core power decays following reactor trip and, subsequently, increases as natural circulation flow develops (Figures 4.6-15 and 4.6-16). Without RCPs running, the upper head region becomes inactive, and the fluid temperature in that region will significantly lag the temperature in the active RCS regions. This creates a situation more prone to voiding during the subsequent cooldown and depressurization.

Sufficient instrumentation and controls are provided to ensure that necessary recovery actions can be completed without offsite power available. Although the recovery methods are the same with or without offsite power available, the equipment used may be different. The RCS is cooled using the PORVs on the intact SGs since neither the steam dump valves nor the condenser would be available without offsite power. Even with one SG out of service, these valves provide sufficient capacity to complete the initial cooldown rapidly, as shown in Figure 4.6-17. Note that the hot leg temperature does not respond as quickly as the cold leg and SG temperatures since RCPs are not running.

Under natural circulation conditions subsequent actions to isolate the affected SGs and cooldown the intact RCS loops may stagnate the affected loop. Consequently, the hot leg fluid in that loop may remain warmer than the unaffected loops. Similarly, SI flow into the stagnant loop cold leg may rapidly decrease the fluid temperature in the cold leg, downcomer, and pump suction regions significantly below the rest of the RCS.

With RCPs stopped, normal pressurizer spray would not be available. Consequently, RCS pressure must be controlled using pressurizer PORVs or auxiliary spray. Although a PORV enables more rapid RCS depressurization (Figure 4.6-18), it also results in an additional loss of reactor coolant which may rupture the PRT and contaminate the containment. Auxiliary spray conserves reactor coolant but may create excessive thermal stresses in the spray nozzle which could result in nozzle failure. Auxiliary spray is recommended only if normal spray and PORVs are not available.

Since the upper head region is inactive, voiding may occur in this region during RCS depressurization. This will result in a rapidly increasing pressurizer level indication as water displaced from the upper head replaces steam released or condensed from the pressurizer. This behavior was observed during the Ginna tube failure event, when the pressurizer PORV failed to close. The extent of voiding is limited to the inactive regions of the RCS provided subcooling is maintained at the core exit. However, flashing in the inactive regions may slow further RCS depressurization to cold shutdown conditions.

Once SI flow is stopped, no additional primary-to-secondary leakage or uncontrolled radiological releases from the affected SGs should occur. This plant response is similar with or without offsite power available.

The automatic protection systems are more than sufficient to maintain adequate core cooling even for multiple tube failures. However, extensive operator actions are required to stop primary-to-secondary leakage which could lead to a steam generator overfill condition if not terminated expeditiously. The system response to a SGTR before and immediately after reactor trip has been described. From this description the symptoms which identify both the tube failure event and the affected SGs should be evident, including high or increasing secondary side radiation, and steam generator level response. These symptoms provide the basis for diagnostics in the emergency operating procedures.

It must be emphasized that although strong similarities exist, each tube failure is unique. Variations in break size and plant specific features, such as SI capacity and operator response times, will affect system conditions.

4.6.3 R.E. Ginna Tube Rupture

On January 25,1982, the R.E. Ginna Nuclear Power Plant experienced a design-basis steam generator tube rupture. This resulted in the maximum flow from a single tube.

The final safety analysis report (FSAR) assumes that the break flow is terminated by operator action within 30 to 60 minutes. The procedures available to the operators at the time proved to be inadequate to meet this time requirement. Several procedure changes have occurred because of these inadequacies. Major changes address specific guidance on safety injection reset and safety injection termination with suspected reactor upper head voiding. Also of major significance are the criteria for tripping and restarting reactor coolant pumps.

The report on the Ginna steam generator tube rupture is published as NUREG-0909. The event is described in nine phases. This nine phase description, along with an event chronology is included as Table 4.6-3 of this chapter. Note that other equipment failures made this event unique, such as PORV failure to close and SG code safety valve failure to fully reseat. Also the design of the CVCS allowed the letdown isolation valve to open, causing overpressure in the pressurizer relief tank (PRT) and release into the containment.

The R.E. Ginna Nuclear Power Plant is a 1520-MWt, two-loop PWR designed by Westinghouse. A diagram of the major plant systems and components is shown on Figure 4.6-19. Figure 4.6-20 shows the instrument locations in the reactor coolant system, pressurizer, and PRT.

4.6.3.1 Event Phase 1: Steady-State Operation (Period before 9:25 a.m., 1/25/82)

Prior to 9:25 a.m., the plant was operating at full power, steady-state conditions. The major primary and secondary system parameters and their steady-state values are listed in Table 4.6-2. These parameters indicate that the plant was in a normal full power condition. No important systems were out of service and no abnormal conditions existed in any of the major parameters.

4.6.3.2 Event Phase 2: Tube Rupture and Initial Depressurization (9:25 a.m. to 9:30 a.m.)

At 9:25 a.m., there was a sudden rupture of a single tube in the B steam generator. Detailed information from the plant process computer is available for the period beginning at 9:26 a.m. This information was used to develop the graphs of pressurizer (PZR) pressure and level versus time (Figures 4.6-21 and 4.6-22). The initial depressurization from 2197 psig to approximately 2100 psig and the associated drop in pressurizer level from 47% to 30% occurred between 9:25:25 a.m. and 9:26:30 a.m. The depressurization and level drop were terminated by automatic and manual actions to increase the charging flow from 30 gpm to at least 60 gpm (corresponding to full flow from one charging pump) and thermal expansion of the water in the reactor coolant system associated with the ordered load reduction. This indicates that the initial leak rate was approximately 750 gpm.

A level deviation alarm resulted when the water level in the B SG exceeded its setpoint of 52%. The water level increased because of the flow from the reactor coolant system to the SG through the ruptured tube. The increased water level was sensed by the feedwater control system, which reduced feedwater flow by modulating the feedwater control valve. The difference between feed flow and steam flow produced the steam flow/feed flow mismatch alarm from the B SG. Simultaneously, a radiation alarm on the air ejector indicated a leak from the reactor coolant system to the secondary system. These were important symptoms of a tube rupture in B SG.

At 9:27:11 a.m. (Figure 4.6-22) a more rapid reactor coolant system depressurization and level decrease began. This was the result of a reactor coolant cooldown and a continuing leak of approximately 750 gpm. This leak resulted in a reactor trip at 9:28

a.m. on low pressurizer pressure (~1900 psig), an automatic safety injection actuation signal on low pressurizer pressure (~1720 psig), and a containment isolation signal on safety injection actuation. The safety injection actuation signal started all three high pressure safety injection pumps and the two motor driven auxiliary feedwater pumps. The containment isolation signal resulted in the closure of all containment isolation valves, termination of main feedwater flow, and termination of charging flow. The turbine driven auxiliary feedwater pump subsequently started automatically on low water level (17%) in both steam generators. Shortly after these actuation signals, the pressurizer emptied of water, and the reactor coolant system pressure dropped to approximately 1200 psig. The minimum system pressure was apparently determined by the temperature of the hottest fluid in the reactor coolant system. This fluid would have flashed when the system pressure dropped below the saturation pressure corresponding to its temperature. This initial flashing in the reactor coolant system would have occurred when the temperatures in the pressurizer surge line and reactor vessel upper head were near or above 576°F, the saturation temperature corresponding to 1270 psig.

Immediately after the reactor, turbine, and feedwater trips, the narrow-range A and B SG water level instruments indicated a level drop from about 47% to about 10%, normal for a trip from full power, while the wide-range level instrument indicated a slight increase in level. This discrepancy was believed to result from cold calibration of the wide-range instrument and the fact that its lower pressure tap was located just above the tube sheet. The narrow-range instrument is calibrated at operating temperature of the SG and its lower pressure tap is located just above the top elevation of the tube bundle.

Approximately 50 seconds after the SI signal occurred, the reactor operators verified that the pressurizer pressure was less than 1715 psig and manually tripped the reactor coolant pumps in accordance with Ginna procedures.

During normal operations, both seal injection and component cooling water are provided to the reactor coolant pumps. The seal injection flow was terminated upon SI because the charging pumps were tripped automatically.

In addition, the piping that returns the seal water to the CVCS was isolated by the containment isolation signal. After the seal return valve closed, reactor coolant system leakage through the reactor coolant pump seals pressurized the seal return line. As shown by the pressurizer relief tank level indication, the relief valve on this line lifted. The pumps can be operated without seal injection provided component cooling water is available and the seal leakage is less than five gpm (Ginna procedure). Therefore, the reactor coolant pump trip was a result of the procedural requirement to trip the pumps to avoid exacerbating certain small-break loss of coolant accidents.

Numerous valves inside containment were affected when the instrument air was isolated at 9:28 a.m from the containment isolation signal. The important valves for this event were the two pressurizer PORVs, the pressurizer spray valves, the CVCS charging and letdown valves, and the pressurizer auxiliary spray valve. Except for the level control valve in the CVCS, all these valves fail closed. The pressurizer PORVs have a backup nitrogen supply that is available to operate the valves.

4.6.3.3 Event Phase 3: Natural Circulation and Reactor Coolant System Repressurization (9:30 a.m. to 10:07 a.m.)

Following the initial depressurization, the SI pumps injected water into the reactor coolant system, increasing the volume of water in the system and increasing the system pressure to 1350 psig. During this period, the reactor-coolant-system-to-B-SG pressure difference was approximately 300 psi and the leakage into the B SG continued at a rate of approximately 400 gpm. Figure 4.6-23 presents estimates of SI flow and break flow versus pressure. This figure indicates that the reactor coolant system and B SG should establish a dynamic equilibrium between high pressure injection flow and break flow with a reactor coolant system pressure of 1410 psig, which corresponds to an indicated reactor coolant pressure of 1385 psig. This condition developed at approximately 10:00 a.m. during the event.

The temperature difference from the cold legs (Figure 4.6-24) to the hot legs initially decreased, since the reactor trip caused a rapid drop in the reactor core heat generation, and reached a minimum value of 20°F. Following the RCP trip at 9:29 a.m., the reactor coolant flow rates decreased. As flow decreased, natural circulation developed, with the reactor core as the heat source, and the elevated steam generators as the heat sink.

At 9:32 a.m. the turbine-driven auxiliary feedwater steam supply valve from B SG was shut in accordance with the SGTR procedure. In addition, the motor-driven auxiliary feedwater pump was isolated from the B SG. To confirm that the leak was from the B SG, as suspected, a check of B steam line radiation level was made using a portable radiation monitor. The indicated reading (approximately 30 mrem/hr) gave positive indication of the affected SG approximately 15 minutes after the initial alarms had indicated that a problem existed.

At 9:40 a.m the B SG was isolated by closing the MSIV, and no further cooling was taking place in the B SG. This caused the flow in the B reactor coolant loop cold leg to stagnate and to reverse direction as water in the B loop cold leg was drawn toward the ruptured tube. The reverse flow in the B reactor coolant cold leg continued throughout the event.

Prior to 9:40 a.m., the reactor coolant leaking into the B SG was circulated throughout the main steam, main feedwater, and condensate systems. After 9:40 a.m. the B SG main steam isolation valve was closed and the tube leak caused an increase in the indicated steam generator water level. The pressure in the B SG began to increase when the turbine-driven auxiliary feedwater terminated at 9:46 a.m. The B SG narrow-range water level indication went off scale high at 9:55 a.m. Later the attached steam line also flooded.

Throughout this phase, the A SG continued to dump steam into the main condenser. The RCS cooldown rate during this period can be seen by observing the change in the A loop temperature versus time in Figure 4.6-24.

The only radiation alarm from the SG blowdown system occurred at 9:50 a.m., 22 minutes after the B SG blowdown piping isolation valve closed on containment isolation. The radiation monitor is located downstream of the sample line isolation valves, which were also closed upon containment isolation.

The SI signal was reset at 9:57 a.m. The containment isolation signal was also reset in order to restore instrument air and gain control of air-operated valves inside containment.

At 10:04 a.m., one charging pump was restarted, although the SGTR procedure called for starting all available charging pumps.

4.6.3.4 Event Phase 4: Pressurizer PORV Operation (10:07 a.m. to 10:15 a.m.)

Reducing the RCS pressure to reduce the tube leakage is an important step in recovery from a tube rupture event. The first attempt to reduce RCS pressure occurred at 10:07 a.m. when one PORV was opened for a few seconds. The valve was successfully cycled three times but failed to close on the fourth cycle at 10:09 a.m. The operators then closed the block valve to terminate flow through the stuck-open PORV. The normal closure time for the block valve is approximately 35 seconds. The plant process computer printout shows that pressure in the RCS was increasing at 10:11 a.m., indicating that the block valve was closed by that time. In addition, the temperature rise in the PRT terminated at 10:12 a.m.

While the PORV was open RCS pressure dropped from 1350 psig to 850 psig (Figure 4.6-25). For the period from 10:09 a.m. to 10:11 a.m. the RCS pressure was lower than the B SG pressure. This low RCS pressure caused a temporary reversal in primary-to-secondary break flow, an increase in SI flow, and flashing of water in the reactor vessel upper head and B SG tubes. While the PORV was stuck open the pressurizer level increased rapidly from 6% to 100%. The pressurizer was filled by water displaced by steam formation in the reactor vessel upper head and inside the B SG tubes, flow from the B SG into the RCS through the ruptured tube, and SI and charging flow.

The indicated rate of increase of pressurizer level, beginning at 10:09 a.m., corresponds to a computed water inventory rate of change of 405 ft^3/min. Since the PORV was opened for about two minutes after 10:09 a.m., approximately 810 ft^3 of water would have left the pressurizer. This value is reasonably close to the estimated value of water volume available, that is 765 ft^3.

Since the water volume in the pressurizer at 10:09 a.m. was approximately 100 ft^3, these calculations imply that a relatively small volume (35 to 100 ft^3) of water was discharged through the PORV after the steam in the pressurizer had been relieved.

A review of the PRT parameters (Figure 4.6-26) indicates that the four percent level increase during the PORV openings corresponds to approximately 40 ft^3 of water.

Since the mass of steam in the pressurizer at 10:07 a.m. corresponds to 35 ft^3 of water at 1400°F, the indicated increase in PRT level implies that only 5 ft^3 of water was discharged through the PORV. Therefore, all the available data indicated that when the PORV failed to close it was discharging steam; that very little liquid discharge took place; and that the liquid discharge occurred at the end of the blow down while the PORV block valve was closing.

During the time when the PORV was open, the indicated cold-leg temperature in the B RCS loop decreased rapidly to 260°F and then recovered to 350°F. These changes are associated with an increase and decrease in SI flow in the B loop cold leg. The SI water was mixing with the hot water from the reactor vessel downcomer and the B loop cold-leg temperature sensor was reading a mixed fluid temperature.

After the pressurizer PORV block valve was closed, the system pressure returned to approximately 1400 psig. This pressure was slightly higher than the pressure recorded before the PORV openings. Except for forming the steam bubble in the upper head and filling the pressurizer with water, the system conditions after the block valve closure were essentially the same as before the PORV opening.

After the operator noted that the PORV block valve indicated closed on the main control board, he directed that the PORV tailpipe temperatures be monitored to insure that the block valve had fully closed and that the other PORV was not leaking. The drop in tailpipe temperature was slower than expected, so the operator closed the block valve associated with the other PORV. It was later determined that there was no leakage past the originally closed block valve or the second PORV.

Throughout this phase of the event, the RCS was being cooled by dumping steam from the A SG to the main condenser. Auxiliary feedwater for the A SG was supplied by the A motor-driven pump from the condensate storage tank.

Instrument air had been restored at 9:59 a.m., but the selected letdown orifice isolation valve (LCV-200B) and level control valve (LCV-427) remained closed because the pressurizer level was below 10%. At approximately 10:08 a.m., the pressurizer level increased above 10%, opening (LCV-427) and the selected orifice isolation valve as designed. The letdown containment isolation valve (AOV-371) remained closed, since the valve does not automatically open when the containment isolation signal is reset. Consequently, the letdown line was communicating with the RCS while the downstream portion of the letdown line remained isolated, and the relief valve opened at a set pressure of 600 psig. This valve relieves to the PRT and was a major contributor to the PRT level increase.

4.6.3.5 Event Phase 5: Prolonged Safety Injection (10:15 a.m. to 10:38 a.m.)

When the RCS pressure and the pressurizer level increased after the PORV block valve was closed at 10:11 a.m., the conditions necessary for allowing termination of SI existed. The plant operators knew; however, that a steam bubble had formed under the reactor vessel upper head and they were reluctant to interpret the high pressurizer level as a legitimate indication of having sufficient RCS inventory. As a result, the termination of SI did not occur until about 10:38 a.m., after discussions were held between control room personnel and the Technical Support Center personnel.

A detailed review of the system data indicate that PORV operation was successful in decreasing RCS pressure and in increasing the liquid inventory by SI and charging flow. Subsequently, SI increased RCS pressure to 1390 psig. SI flow could have been safely terminated immediately after the PORV block valve closed at 10:11 a.m.

After 10:11 a.m. the continued SI caused the RCS pressure to remain approximately 300 psi above the B SG pressure. This pressure differential caused the leakage to the SG to persist. As a direct result of the leakage into the B SG, the pressure increased to 1080 psig at 10:19 a.m., and the opening of a SG safety valve released steam into the atmosphere. This occurred again at 10:28 a.m. The first and second SG safety valve openings each resulted in pressure reductions of approximately 50 psi. The A and B SG valve position recorders were started by a technician earlier in the event, but the recorders failed to indicate these and subsequent valve lifts.

The repeated openings of the SG safety valve led the control room and Technical Support Center personnel to decide to terminate SI.

4.6.3.6 Event Phase 6: Safety Injection Termination and Leakage Reduction (10:38 a.m. to 11:21 a.m.)

The SI pumps were stopped at 10:38 a.m. and the RCS pressure decreased to approximately 950 psig. The secondary pressure continued to decrease to approximately 850 psig as a result of the third opening of the SG safety valve. This SG pressure reduction of approximately 200 psi is unusually large and indicates that this valve did not close normally, possibly as a result of discharging two-phase flow. With an RCS-to-SG DP of 100 psi, the leak rate was reduced to approximately 150 gpm. As a result of the continuing leakage, the pressure difference between the RCS and the B SG gradually decreased over the next 40 minutes, falling to 30 psi at about 11:19 a.m.

At about 10:40 a.m. the pressurizer heaters were re-energized to establish a steam bubble in the pressurizer. The pressurizer heaters had tripped on low pressurizer level during the initial depressurization.

At about 10:42 a.m., a second charging pump was started. As indicated in Figure 4.6-25, the equilibrium RCS pressure was approximately 40 psig above the pressure in the B SG with the two charging pumps running. Continued charging flow while letdown remained isolated caused the RCS-to-SG pressure differential to persist and the break flow to continue.

During this phase of the event, the method of dumping steam from the A SG was changed to allow steam to be vented to atmosphere through the atmospheric PORV on the A SG. The steam had been dumped to the condenser until the last operating condensate pump was secured at 10:40 a.m. Without condensate flow, the air ejector automatically secured, and the vacuum in the condenser was not maintained. The decision to stop dumping steam to the condenser was made to prevent any further contamination of the condensate system, particularly the condensate demineralizers.

Also, during this phase of the event, the RCS pressure increased from 950 to 1050 psig. Initially the increase was caused by operators throttling closed the A SG PORV with a corresponding decrease in heat removal from the RCS. After 11:07 a.m., when one of the SI pumps was restarted, the RCS pressure increased when the SI pump added water. The SI pump had been restarted as a precaution against a large pressure reduction which could be caused by the restart of the A reactor coolant pump.

One B SG safety valve opened a fourth time as a result of the RCS pressure increase caused by the operation of the SI pump.

During this phase, both the letdown line relief valve and the seal return relief valve continued to lift and discharge water to the PRT. As shown in Figure 4.6-26, the PRT water level increase indicates that the letdown relief valve was the major contributor to the tank inventory increase, which resulted in the burst of the tank rupture disc at about 10:52 a.m. The letdown relief valve remained open until 12:02 p.m. The estimated flow rate through the letdown relief valve was about 24 gpm based on the rate of change in PRT level indication between 10:15 and 10:45 a.m., 22 gpm based on PRT and containment sump inventory balance.

4.6.3.7 Event Phase 7: Reactor Coolant Pump Restart (11:21 a.m. to 11:37 a.m.)

This phase of the event began with the restart of the A RCP at 11:21 a.m. No detailed information is available for the period immediately before or immediately after the time when the pump was restarted because of computer failure.

Although there is no computer recorded data for the period during the pump restart, later computer data (about 12 minutes after pump restart) and hand written logs of the thermocouple data indicated that the temperature reduction in the upper head region was very rapid and occurred very soon after the restart of the RCP. All the data after the time of pump restart showed that, with the exception of the pressurizer, the entire RCS was at approximately the same temperature for the rest of the event.

The reactor vessel upper head temperatures had been below the saturation temperature corresponding to the RCS pressure since 10:11 a.m. but were significantly higher than the temperatures in the remainder of the RCS, with the exception of the pressurizer. At 11:21 a.m., a steam bubble of less than 300 ft^3 may still have existed in the upper portion of the reactor vessel. There is no instrumentation at higher elevations which would detect such a bubble. After the RCP restart the indicated temperature in the upper head decreased to a value equal to the temperature in the remainder of the RCS, approximately 400°F. With the RCP running and more than 100°F of subcooling at the upper head thermocouple locations, it is unlikely that any steam existed in the upper head at this time or later.

The limited data available indicate that it is likely that a small RCS-to-SG differential pressure, perhaps 40 psid, existed throughout this period. The corresponding leak rate would be 100 gpm.

Throughout this phase of the event, one SI pump was operated as a precaution against an uncontrolled depressurization associated with the RCP restart. Such a depressurization was of concern to the plant staff because the pressurizer level was still off scale and a steam bubble was thought to exist in the reactor vessel upper head. It should be noted that the B SG would have provided water through the ruptured tube to help suppress any large pressure changes. The primary results of operating the SI pump were the two additional openings of the B SG safety valve. These openings of the valve will be discussed further in the next phase of the event. The depressurization associated with the RCP restart was limited to about 100 psi, apparently as a result of steam formation in the pressurizer (above the range of indicated levels) and increased SI flow.

4.6.3.8 Event Phase 8: Leaking Steam Generator Safety Valve (11:37 a.m. to 12:27 p.m.)

At 11:37 a.m., the B SG's safety valve opened for the fifth time, as a result of the continuing SI. The data indicated that the valve did not close until pressure in the SG decreased to 840 psig. This value is about the same as that for one of the earlier valve openings and is considerably below the pressure at which the valve would normally close. This abnormal behavior may again be attributed to the fact that the valve discharged liquid rather that the steam for which it had been designed.

After the B SG safety valve closed, the pressure differential between the RCS and the B SG was more than 100 psid.

Safety injection flow was terminated at about the same time as this last valve opened. However, the RCS to SG differential pressure was significantly higher than for the comparable conditions at 10:38 a.m. Three additional facts indicate that this phase is significantly different from earlier phases of the event. First, the reduction in B SG pressure at approximately 12:05 p.m., while the RCS pressure was more than 100 psi higher, cannot be explained unless there was significant mass or energy removal from the SG. Cooling of the B SG was in progress at this time; however, the observed rate would not support such a pressure difference. Second, the indicated differential pressure implies a large flow, estimated to be 100 to 200 gpm, into the SG over a long period of time (50 min.). Since the B SG appears to have been full at 11:37 a.m. (the time of the last valve opening), it appears very unlikely that the SG could accommodate an additional 5,000 to 10,000 gallons of water. Third, the rapid increase in B SG pressure at about 12:25 p.m. was similar to that experienced when the safety valve closed earlier in the event. These facts tend to conclude that it is very likely that the B SG safety valve failed to fully reseat following the opening at 11:37 p.m. and that the valve leaked at a rate of 100 to 200 gpm for approximately 50 min. This release rate is approximately two to four percent of the valve capacity and was probably not noticed by the plant staff because its noise and steam discharge were masked by the noise and steam from the nearby A SG atmospheric PORV. The mass balance also tends to support the position that the safety valve failed to properly reseat for 50 min.

At 11:52 a.m., the pressurizer level indication came back on scale. The estimated rate of leakage through the B SG safety valve and the continued plant cooldown would explain the return of the pressurizer level during the period when charging flow exceeded letdown. The maximum rate of decrease of the indicated pressurizer level agreed well with that predicted by calculations. Normal letdown had been restored at about 12:02 p.m. At about 12:12 p.m., one SI pump was restarted, apparently for the purpose of arresting the decrease in pressurizer level caused by continuing leak into the B SG. The SI pump was then operated intermittently to control pressurizer level throughout the remainder of this phase.

4.6.3.9 Event Phase 9: Leak Termination and Cooldown (12:27 p.m., 1/25/82 to 10:45 a.m., 1/26/82)

At about 12:25 p.m., the B SG safety valve appears to have seated. The SG indicated pressure then increased to a value slightly above the RCS pressure, and the RCS leak was terminated. At about 12:35 p.m., the SI pump was stopped; it was no longer needed to control pressurizer level.

The break flow was controlled by attempting to maintain the RCS pressure at about 25 psi below the B SG pressure during the RCS cooldown and depressurization. The B SG was, therefore, leaking water back into the RCS during this phase of the event. The B SG cooldown was being controlled by the heat transfer from it to the RCS.

After 12:27 p.m., the cooldown proceeded at a very slow rate, which allowed time for the RCS to be degassed before using the RHR system (the low pressure and low temperature decay heat removal system). During this phase of the event, the B SG water level indication came back on scale on the narrow-range instrument at approximately 6:40 p.m., January 25, 1982.

Estimated break flow for an indicated 25 psi differential pressure was calculated and found to be about four times larger than that expected based upon the rate of level decrease observed in the B SG. The rate of change of the B SG wide range water level indicating implies a 37 gpm leak rate. The return from being off-scale after seven hours of leakage back into the RCS implies approximately a 39 gpm leak rate. Considering the limited data available, these values are considered to be in good agreement.

Since the B SG pressure sensor is at an elevation approximately 60 ft above the elevation of the pressure sensor in the RCS loop and the SG was flooded with water, the actual pressure differential at the break would have been 28 psi greater than indicated. Therefore, an indicated SG pressure 25 psi greater than the RCS pressure would mean a break differential pressure of 53 psi, which would have supported a much larger leak rate of approximately 150 gpm. For the leak rate to have averaged 36 gpm, the pressure difference must have been less than three psi. After reviewing the reactor coolant loop pressure measurements and all three B SG pressure measurements for the cooldown phase, particularly the pressure oscillations occurring between 8:00 p.m. and 11:00 p.m., January 25 (see Figure 4.6-27), the reactor coolant loop pressure measurement was in error (too low) by approximately 50 psi. This error was recognized by the plant staff sometime during this phase and may have existed throughout the entire event, since a similar bias can be seen in the data at 9:26 a.m. An error of this magnitude is not surprising in a pressure instrument with a range of 0 to 3000 psig.

(NOTE: A normal pressure instrument accuracy specification is one percent of full scale, which for this instrument is 30 psi).

The fact that the B SG pressure did not decrease to the saturation pressure corresponding to the temperature of the water being pumped through the SG tubes, indicates that thermal stratification existed in the generator and its attached main steam line. Thermal stratification is to be expected in a steam system which has been over filled, particularly for a design like that of Ginna in which the upper internals impede water volume communication and the steam line slopes downward toward the turbine and allows hot water to be trapped. This information, together with the information on the leak rate, indicates that the primary reasons for the slow depressurization of the B SG were (1) the extremely small pressure differential between the RCS and B SG, and (2) the thermal stratification of the water in the SG, which prevented complete cooling.

After 12:25 p.m., January 25 the flow through the ruptured tube was from the B SG into the RCS. Under this condition, there is concern for potential dilution of the boric acid in the RCS. The boron concentrations in the B SG and the RCS were checked before cooldown and depressurization began and at approximately half- hour intervals thereafter. The B SG samples indicated 1100 ppm boron. Because of the amount of boric acid injected into the RCS from the boric acid storage tanks and refueling water storage tank, there was never any potential for an inadvertent criticality (the boron concentration needed to maintain the required shutdown margin was approximately 700 ppm) because of boron dilution during this event.

At approximately 6:40 p.m., the B SG narrow-range water level indication was on-scale, and auxiliary feedwater was supplied for the first time since 9:32 a.m. This was done to assist in the cooldown of the B S/G and helped to degas it.

When the B SG was depressurized, a gas mixture was found that included hydrogen and gaseous fission products, such as xenon, both of which are normally found in the RCS. Some fission products are always found in PWRs. The presence of these non-condensable gases may have also contributed to the slow depressurization of the SG.

The RHR system was placed in service at about 7:00 a.m. on January 26, 1982. The plant staff chose to maintain system conditions without substantial RCS cooldown while the RCS was cleaned and degassed using the CVCS at a letdown rate of 50 to 60 gpm.

TABLE 4.6-1 Typical Sequence Of Automatic Actions Following a Double-Ended SGTR

EVENT/SIGNAL	TIME (sec) OFFSITE POWER	TIME (sec) NO OFFSITE POWER
Tube Failure	0	0
Reactor Trip Signal	232	232
Loss of All A/C Power	—	232
Steam Dump Operation	233	—
Turbine Isolation	234	234
Safety Valve Operation	—	245
SI Signal	250	386
Main FW Isolation	257	393
AFW Actuation	310	446*

TABLE 4.6-2 GINNA System Parameters

Parameter	Value	Parameter	Value
General:		Auxiliary Feedwater:	
Licensed power	1520 MWt	Motor-driven	2
Plant capacity	490 MWe	capacity	200 gpm (ea)
Number of loops	2	start signals	lo-lo S/G level
Loop isolation valves	none		trip MF pumps
			SIS
Steam Generators:		Turbine-driven 1	
Secondary water volume:		capacity	400 gpm
full load	1681 cu ft	start signals	lo-lo level (both S/G's)
no load	2821 cu ft		Loss of Power
Level at full load	52%		(both 4kVbuses)
Level at no load	39%		
Secondary Steam Volume:		Standby AFW System	Manual
full load	2898 cu ft		
no load	1758 cu ft	MSIV Automatic Closure	
A S/G to MSIV	776 cu ft	Modes All Lines:	
B S/G to MSIV	1055 cu ft	(1) High-high steam flow, and SIS	3.6E6 lb/h
Steam Pressure at full load	755 psig		
no load	1055 psig	(2) High steam flow, low Tavg and SIS	0.4E6 lb/h
Primary water volume	944 cu ft		
U-tubes per S/G	3260	(3) High Containment Pressure	18.0 psig
Allowed leakage	0.1 gpm		
S/G safety valves	4		
setpoints	1085 psig	MSIV closure time	1.0 sec.
3 at	1140 psig		
Flow rate each S/G	3.3E6 lb/h	Charging System :	
at 1100 psig	0.82E6 lb/h	Number of pumps	3
PORV's each S/G	1	Type	Pos. Disp.
operation	auto at > 1050 psig or manual	Design flow ea.	60 gpm
		Normal Charging Flow	30 gpm
capacity	10 % power	Normal Letdown Flow	40 gpm
		Normal RCP seal supply	16 gpm
Steam Dump Bypass:		Normal RCP seal return	6 gpm
modes	T_{avg}-T_{ref}	Automatic letdown isolation	Low Pzr Pressure
	Steam Pressure	Automatic Trip	Safety Injection
capacity	40 %		

TABLE 4.6-2 GINNA System Parameters (Continued)

Parameter	Value	Parameter	Value
Reactor Coolant System:		High Pressure Safety Injection	
Total Volume	6245 cu ft	Number of pumps	2
Total RCS Flow	64.3E6 lb/h	Type	Centrifugal
RCP thermal output	30E6 btu/h	Design flow	300 gpm
Tavg at full load	573°F	Shut-off pressure	1520 psig
		Boron Injection with SIS	Initially from BAST
no load	547°F		then RWST
Reactor vessel head temp.	590°F	Accumulators	
Nominal system pressure	2200 psig	Number	2
low pressure scram Setpoint	1873 psig	Pressure	700 psig
Pressurizer:		Refueling Water Storage Tank	
Total Volume	800 cu ft	Capacity	3.38E5 gal
Water volume@ full load	480 cu ft	Boron concentration	>2000 ppm
Total heater Capacity	800 kW	Design Pressure	121 psig
Spray nozzle ΔT Limit	320°F		
		Boric Acid Storage Tank	
Pressurizer PORV's		Number	2
Number	2	Capacity, ea	3600 gal
Set pressure	2335 psig	Boron concentration	20,000 ppm
Flow rate	1.79E6 lb/h		
		Main Feedwater Pumps	
Pressurizer Relief Tank		Number	2
Rupture Disc Design	100 psig	Type	Centrifugal
Capacity	800 cu ft	Capacity, ea	50% of FP
		Flow rate, ea	14,000 gpm
Pressurizer Safety Valves		Operating pressure	853 psig
Number	2	Shut-off head	1180 psig
Operating Pressure	2485 psig	Drives	Electric
Flow rate @ 2500 psig	0.228E6 lb/h		
		Isolation Signals	
Pressurizer Level			
		S/G high level	67 %
Full Load	47 %	SIS	
No Load	22 %		
		Trips	
Safety Injection Actuation Setpoints			
Low Pressurizer Pressure	1723 psig	1. Loss of Offsite Power	
High Containment Pressure	4 psig	2. Overcurrent	
Low Steamline Pressure	514 psig	3. Thermal Reload	

TABLE 4.6-3 GINNA Event Chronology

Time and Event	Comment
January 25, 1982	
9:22 a.m.	
Initial conditions: plant power, 100%; indicated reactor coolant system (RCS) loop pressure, 2197 psig; indicated RCS loop average temperature, 572°F; indicated pressurizer pressure, 2235 psig; other primary secondary parameters normal; primary-to-secondary leak rate, 0 gpm.	The primary-to-secondary leak rate was last calculated based on air ejector monitor indications on January 7, 1982. Air ejector radiation monitor indications had been essentially constant since January 24, 1982. No known plant operations that would have caused or affected the event were in progress.
9:25 a.m.	
The following alarms were received in the control room: charging pump speed alarm; B steam generator level deviation alarm; B steam generator steam-flow/feed-flow mismatch alarm; pressurizer level and pressure deviation alarms; air ejector radiation monitor (R-15) alarm; pressurizer low pressure alarm (Setpoint, 2185 psig).	First indications of the tube rupture in B steam generator. One charging pump, which was in automatic pressurizer level control, was now at its maximum speed. The speed of a second charging pump, which had been on manual control, was increased by the operator. The third charging pump was not operating.
9:26 a.m.	
The Shift Supervisor ordered power reduction. One operator fast closed the turbine control valves; another operator commenced normal boration.	The Shift Supervisor was initially in his office which was located off the main operating area of the control room. He was called to the control room by an operator after the first alarm annunciated.
The following alarms were received in the control room: reactor coolant loop low pressure alarm (set-point, 2064 psig); over temperature ΔT turbine runback because of decreasing pressurizer pressure; main steam dumps armed alarm.	The over temperature AT Setpoint is a computed value which is a function of pressurizer pressure and reactor coolant system average temperature.
9:27 a.m. (about)	
All eight main steam dump valves opened automatically.	Steam dump valves opened in automatic control in response to error signal derived from the difference between RCS coolant reference and average temperature.
The third charging pump was manually started by the operator.	All three charging pumps were running at this time. The RCS pressure and pressurizer level decreased as a result of flow through the rupture (break flow). The rate of indicated decrease was consistent with the break flow and the combined effects of high charging flow and the RCS swell from the turbine down-power transient.

TABLE 4.6-3 GINNA Event Chronology (continued)

Time and Event	Comment
The containment fan-cooler, service-water discharge radiation monitor (R-16) alarmed.	Alarm probably resulted from the proximity of the instrument to the B main steam line in the Intermediate Building.
9:28 a.m.	
Four main steam dump valves closed automatically.	
The following also occurred: pressurizer level low alarm (Setpoint, 10.5%); automatic reactor trip on low pressurizer pressure (Setpoint 1873 psig adjusted by a rate factor); automatic safety injection as a result of safety injection actuation; main turbine automatic trip on reactor trip; A and B steam generator low level alarms; automatic start of both A and B motor-driven auxiliary feed pumps on safety injection; main feedwater automatic isolation and main feedwater pump automatic trip on containment isolation.	The steam generator low levels resulted from the combined effects of the power reduction, reactor, main turbine and main feedwater pump trips. The RCS depressurization rate increased at this time. The break flow had not increased, but the effects of increasing RCS temperature due to the turbine load reduction were no longer present. Further, all charging pumps automatically tripped as a result of safety injection actuation. Letdown isolation valve LCV427 closed on low pressurizer level; the in-service orifice isolation valve closed on interlock with LCV427 controls. The reactor coolant pump (RCP) seal return line isolated on containment isolation. Leakage through the RCP seals pressurized the seal return piping. As shown by pressurizer relief tank (PRT) level indication, the seal return relief lifted. The contribution of this relief to PRT inventory was insignificant.
9:29 a.m.	
The main electrical generator output breakers automatically tripped.	
Both RCPs were manually tripped. Pressurizer level indicated about 0%.	Ginna Emergency Procedures E-1 .1 and E- 1.4 require tripping RCPs at <1715 psig; Westinghouse Owners' Group guidance recommends a lower trip pressure. Licensee requires an RCP trip at a higher pressure because Ginna lacks an environmentally qualified pressure instrument capable of reading these lower pressures.

TABLE 4.6-3 GINNA Event Chronology (continued)	
Time and Event	Comment
9:29 a.m. (about)	
Both steam supply valves to the turbine-driven auxiliary feedwater pump opened automatically because of low-low level in both steam generators.	
9:30 a.m.	
Four main steam dump valves closed automatically.	All steam dumps were now closed.
Initial RCS depressurization stopped at about 1200 psig.	Based on post-event data evaluation, the Task Force concluded a steam bubble may have formed in the reactor vessel upper head at this time. Termination of pressure drop was apparently due to the effects of the establishment of saturation conditions in the reactor vessel upper head along with safety injection.
9:32 a.m. (about)	
The B motor-driven auxiliary feedwater pump was secured manually.	
The B steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually	The turbine-driven auxiliary feedwater pump was now being supplied steam from the A steam generator only.
9:33 a.m.	
The Shift Supervisor notified the NRC Operations Center via the Emergency Notification System (ENS) phone. The Shift Supervisor reported a reactor trip from 100% power as a result of a steam generator tube rupture. The identity of the ruptured steam generator and release information was not given at this time.	The Shift Supervisor made the ENS report using the ENS phone in his office. He suspected that the B steam generator contained the fault but chose to confirm the situation before identifying the faulted steam generator to the NRC. After the initial report, a licensed reactor operator, who was not part of the on-shift crew, manned the ENS in the control room.
The Shift Supervisor declared an Unusual Event.	The Shift Supervisor declared the Unusual Event during his discussion with the NRC Headquarters Duty Officer; the Plant Superintendent was unaware of this declaration. The declaration of an Unusual Event was made in accordance with the Ginna Emergency Plan Implementing Procedures.

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TABLE 4.6-3 GINNA Event Chronology (continued)	
Time and Event	Comment
9:38 a.m.	
Various main steam dump valves began to cycle open and closed.	Main steam dump valves were now being operated in the pressure-control mode. The operator was manually controlling these valves to cause a plant cooldown as required by the steam generator tube rupture procedure.
9:40 a.m.	
The B main steam isolation valve (MSIV) was manually closed and the B steam generator was isolated as required by the steam generator tube rupture (SGTR) procedure. Plant cooldown was being maintained by dumping steam from A steam generator to the main condenser. The licensee declared an Alert.	Along with closing the MSIV, B steam generator isolation included automatic closure of the feedwater supply, blow down and sample valves on containment isolation, manual closure of its auxiliary feedwater supply, and manual closure of the steam supply valve from B steam generator to the turbine-driven auxiliary feedwater pump. RCS pressure and reactor vessel upper head temperature data indicated that the steam bubble in the reactor vessel upper head had been essentially collapsed by safety injection flow.
9:46 a.m.	
The A steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually.	The turbine-driven auxiliary feedwater pump was now secured.
9:48 a.m.	
The A motor-driven auxiliary feedwater pump was manually stopped to control A steam generator level.	No feedwater pumps were operating at this time.
9:50 a.m.	
The steam generator blow down radiation monitor (R-19) alarmed.	R-19 monitors radiation levels on a section of the blow down system piping common to both A and B steam generators. The alarm at this time may have been caused by activity from the B steam generator spreading through the system because of steam generator sample valves that the licensee indicated had a history of leaking.

TABLE 4.6-3 GINNA Event Chronology (continued)	
Time and Event	Comment
9:53 a.m.	
The B steam generator power-operated relief valve (PORV) was manually isolated by an auxiliary operator closing a local, upstream, manual valve.	Operators stated that they manually isolated the B steam generator atmospheric PORV to minimize the potential for a release that would result from high steam generator pressure lifting the PORV. The control room operators interpreted the step in the tube rupture procedure which directed them to place the PORV in the manual closed position to mean that the local manual PORV isolation valve should be closed. Closing this isolation valve made the PORV unavailable for use in reducing B steam generator pressure and resulted in five challenges to an unisolable steam generator safety valve.
9:55 a.m.	
B steam generator narrow-range level indicated off-scale high even though all feedwater supplies to the B steam generator had been isolated earlier in the event.	
9:57 a.m.	
Safety injection initiation circuitry was manually reset; containment isolation was then reset.	Safety injection was reset to permit resetting of the containment isolation signal. Containment isolation was reset to permit restoration of instrument air to the containment. Instrument air would be required to operate various valves inside containment, including the pressurizer power-operated relief valves.
9:59 a.m. (about)	
Instrument air was restored to containment.	Because letdown isolation valve LCV427 fails open on loss of instrument air pressure, it could have opened subsequent to containment isolation. If LCV427 had opened, restoration of instrument air would have caused it to close at this time.
10:00 a.m.	
A and C condensate pumps were manually stopped.	The B condensate pump was still running.
10:03 a.m.	
All main steam dump valves were now closed.	
10:04 a.m.	
One charging pump was manually restarted.	

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TABLE 4.6-3 GINNA Event Chronology (continued)

Time and Event	Comment
10:07 a.m.	
As directed by the SGTR procedure, pressurizer PORV PCV430 controls were manually cycled open and closed twice from the control room. RCS pressure, PRT pressure, level and temperature and PORV valve position indication in the control room demonstrated the valve successfully operated.	Shortly after the PORV was operated, pressurizer level increased above the letdown isolation setpoint. Letdown isolation valve LCV427 and the selected letdown orifice isolation valve then opened. This resulting in lifting the letdown relief valve and adding water to the PRT. The Task Force determined the letdown relief valve was the major contributor to the PRT water level increase
10:08 a.m.	
Pressurizer PORV PCV430 controls were manually cycled again from the control room and the valve successfully operated.	
10:09 a.m.	
Pressurizer PORV PCV430 controls were manually cycled again. The valve opened as desired. After the operator placed the controls in the closed position, the valve started to close but then reopened and stuck open. The operator placed the PORV block valve control switch in the closed position. RCS pressure dropped to about 900 psig; pressurizer level increased rapidly. The pressurizer relief tank (PRT) high-pressure alarm was received in the control room.	The rapid rise in pressurizer level exceeded that attributable to safety injection and charging flow and was the first clear indication to the control room staff that a steam bubble had formed in the reactor vessel upper head. This was, in fact, the second time a steam bubble had formed in the upper head region. The bubble grew as RCS pressure dropped.
10:10 a.m.	
The PRT high-temperature alarm was received in the control room.	
10:11 a.m.	
PORV block valve PCV516 indicated fully closed; pressurizer level indicated	Operator also closed block valve PCV515 to isolate the other pressurizer PORV, PCV431C.
10:17 a.m.	
The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.	

TABLE 4.6-3 GINNA Event Chronology (continued)	
Time and Event	Comment
10:19 a.m. (about)	
One B steam generator safety valve lifted and closed.	Safety injection and charging flow maintained RCS pressure greater than B steam generator pressure, resulting in continued RCS in-leakage into the ruptured steam generator. RCS pressure exceeded the lowest setpoint of the B steam generator safety valves (nominally, 1085 psig). The B steam generator safety valve may have closed and then started to leak steam after this first opening.
10:26 a.m.	
The PRT high level alarm was received in the control room.	
10:28 a.m. (about)	
One B steam generator safety valve lifted and closed.	The B steam generator safety valve position recorder failed to indicate this or subsequent safety valve lifts. The operators heard these lifts from the control room and estimated their duration based on aural information.
10:29 a.m.	
The A motor-driven auxiliary feedwater pump was manually stopped.	
10:38 a.m. (about)	
One B steam generator safety valve lifted and closed.	
Safety injection was terminated by the operators to prevent further release through the B steam generator safety valve.	Charging flow was maintained.
10:40 a.m.	
The B condensate pump and the condensate system were secured; the air ejector secured automatically following loss of condensate flow. The A steam generator PORV was manually throttled open to continue the plant cooldown by relieving the A steam generator to atmosphere.	The licensee secured the condensate system to minimize the spread of radioactive contamination to the condensate storage tanks (CSTs) and the condensate demineralizer system. Securing the condensate system made the main condenser unavailable.
10:42 a.m. (about)	
A second charging pump was started.	
The pressurizer heaters were re-energized to establish a steam bubble in the pressurizer.	The pressurizer heaters tripped on low pressurizer level during the initial depressurization.

3

TABLE 4.6-3 GINNA Event Chronology (continued)	
Time and Event	Comment
10:44 a.m. The licensee declared a Site Area Emergency and executed a site evacuation .	Nonessential personnel were evacuated to the licensee's training center which was downwind of the plant and within the path of the release plume.
10:52 a.m. (about) The PRT rupture disc ruptured, releasing water to the A containment sump.	The disc ruptured primarily because of the letdown relief flow; pressurizer PORV openings and RCP seal return relief were minor contributors to the PRT level transient which finally caused the disc rupture.
10:59 a.m. The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.	From this time in the event, until the plant was cooling down on the residual heat removal system, the A motor-driven auxiliary feedwater pump was run intermittently to control A steam generator water level.
11:07 a.m. (about) One safety injection pump was manually restarted from the control room. The safety injection pump discharge valve was locally throttled to prevent B steam generator safety valve lifts.	The safety injection pump was started in anticipation of an RCS pressure drop that might result from restarting an RCP. This action was not required by the SGTR procedure but was taken as a direct result of the inability to reestablish normal pressurizer pressure control.
11:19 a.m. (about) One B steam generator safety valve lifted and closed. The process computer failed. It remained out of service until about 11:35 a.m.	The licensee manually read reactor vessel upper head and core exist thermocouples to verify adequate core cooling and to determine subcooling in the core and reactor vessel upper head. Any remaining steam bubble in the reactor vessel upper head region, at this time, would have had a volume of less than 300 ft^3.
11:21 a.m. (about) The A RCP was restarted; reactor vessel upper head thermocouple temperatures approached core exit temperatures; pressurizer level indications remained off-scale high. One charging pump was stopped.	A steam bubble in the reactor vessel upper head region would have been condensed by the cooler loop water now forced into this region. Since the pressurizer level instruments were calibrated for operating conditions, the actual pressurizer level would have to drop below 80% before indicated level would respond. The pressurizer volume above 80% actual level is approximately 200 ft^3.

TABLE 4.6-3 GINNA Event Chronology (continued)	
Time and Event	Comment
11:37 a.m. (about) One B steam generator safety valve lifted and closed; the safety injection pump was stopped.	Based on the indicated pressure differential between the RCS and the B steam generator, and on an RCS inventory balance calculation, the Task Force determined the safety valve failed to fully reseat. It remained partially open until about 12:25 p.m., leaking water at a rate estimated to be about 100 gpm.
11:43 a.m. (about) The plant vent particulate radiation monitor (R-13) and the plant iodine monitor (R-10B) alarmed.	The licensee stated that the R-l3 and R-10B monitor alarms were probably caused either by increased background radiation in the vicinity of these monitors or by the Auxiliary Building ventilation system drawing outside air into the building after the steam generator safety valve lifts. It should be noted that no plant noble gas radiation monitor (R-14) alarm was received at this time. The reason this alarm did not occur has not been determined.
11:52 a.m. Pressurizer level indications returned on scale; a steam bubble had been reestablished in the pressurizer.	The maximum rate of change of pressurizer level indication, which occurred about 12:10 p.m., agreed well with that predicted by analysis of the effects of the existing cooldown, charging and letdown rates and the break flow predicted by the Task Force model.
12:02 p.m. Normal letdown was restored.	
12:12 p.m. (about) One safety injection pump was started from the control room.	The safety injection was restarted to terminate the rapid decrease in pressurizer level. The pump was operated intermittently over the next 23 minutes to control pressurizer level.
12:27 p.m. The RCS and B steam generator indicated pressures equalized.	The B steam generator pressure trend indicated that the B steam generator safety valve reseated completely.
12:34 p.m. (about) The RCP seal water return isolation valve was manually opened.	RCP seal return relief reseated at this time.

TABLE 4.6-3 GINNA Event Chronology (continued)

Time and Event	Comment
12:35 p.m. (about) Intermittent operation of the safety injection pump was stopped.	
1:16 p.m. The A MSIV was manually closed.	
2:00 p.m. The licensee reported containment sump A level as 9.3 feet (approx. 8000 gallons); PRT level at 92%.	Containment sump A has two channels of level indication. Channel I indicated *5.3* feet (1,900 gallons); channel 2 indicated 9.3 feet (8,000 gallons). Later, it was discovered that channel 2 was in error.
6:40 p.m. (about) Narrow-range water level indication for the B steam generator returned to the indicating range. Plant cooldown continued via the A steam generator PORV with the A RCP providing flow through the A loop and back flow through the B loop. The operators maintained indicated RCS pressure 25 psi below B steam generator pressure. The B steam generator was being cooled by intermittently feeding it with auxiliary feedwater while bleeding it via the ruptured tube to the RCS.	The plant staff was concerned that water in the B main steam line might flash to steam if the steam generator was cooled and depressurized too quickly. Flashing in the main steam lines could have caused a water hammer, which could have over stressed the main steam line hangers. Therefore, the plant staff decided to pin these hangers and to conduct a slow cooldown. Because of an instrument calibration error in the RCS loop pressure instrument, the actual RCS-to-B steam generator pressure differential was about 3 psi and very little steam generator-to-RCS flow existed. To provide warning of excessive boron dilution in the RCS as a result of the B steam generator feed-and-bleed process, the plant staff sampled the RCS for boron concentration at half-hour intervals. The feed-and-bleed cooldown process caused the level in the CVCS Holdup Tanks to increase and the plant staff discussed the consequences of these tanks filling. The capacity of these tanks was not approached.
7:04 p.m. An operator again attempted to shut pressurizer PORV PCV430; the valve remained open.	
7:17 p.m. The licensee downgraded the Site Area Emergency to an Alert.	

TABLE 4.6-3 GINNA Event Chronology (continued)

Time and Event	Comment
January 26, 1982	
7:00 a.m. (about) The residual heat removal (RHR) system was placed in service to continue the plant cooldown. The A RCP remained in operation.	The RCP remained in operation to assist in RCS degasification and cleanup in preparation for opening the primary-side man-way on B steam generator. At low steam pressures in the A steam generator, the capacity of the A steam generator PORV had limited the plant cooldown rate.
10:45 a.m. The licensee downgraded the Alert to the Recovery Phase.	

TABLE 4.6-4 SGTR Accidents at Pressurized Water Reactors			
Plant	**Date**	**Leak Rate** (gpm)	**Cause**
Point Beach Unit 1	February 26, 1975	125	wastage
Surry Unit 2	September 15, 1976	330	PWSCC in U-bend
Doel Unit 2	June 25, 1979	135	PWSCC in U-bend
Prairie Island 1	October 2, 1979	390	loose parts
Ginna Unit 1	January 25, 1982	760	loose parts and tube wear
Fort Calhoun	May 16, 1984	112	ODSCC at a crevice
North Anna Unit 1	July 15, 1987	637	high cycle fatigue in a U-bend
McGuire Unit 1	March 7, 1989	500	ODSCC in the free span
Mihama Unit 2	February 9, 1991	700	high cycle fatigue
Palo Verde Unit 2	March 14, 1993	240	ODSCC
Indian Point Unit 2	February 15, 2000	150	PWSCC in U-bend

Figure 4.6-1 Closeup View of SGTR

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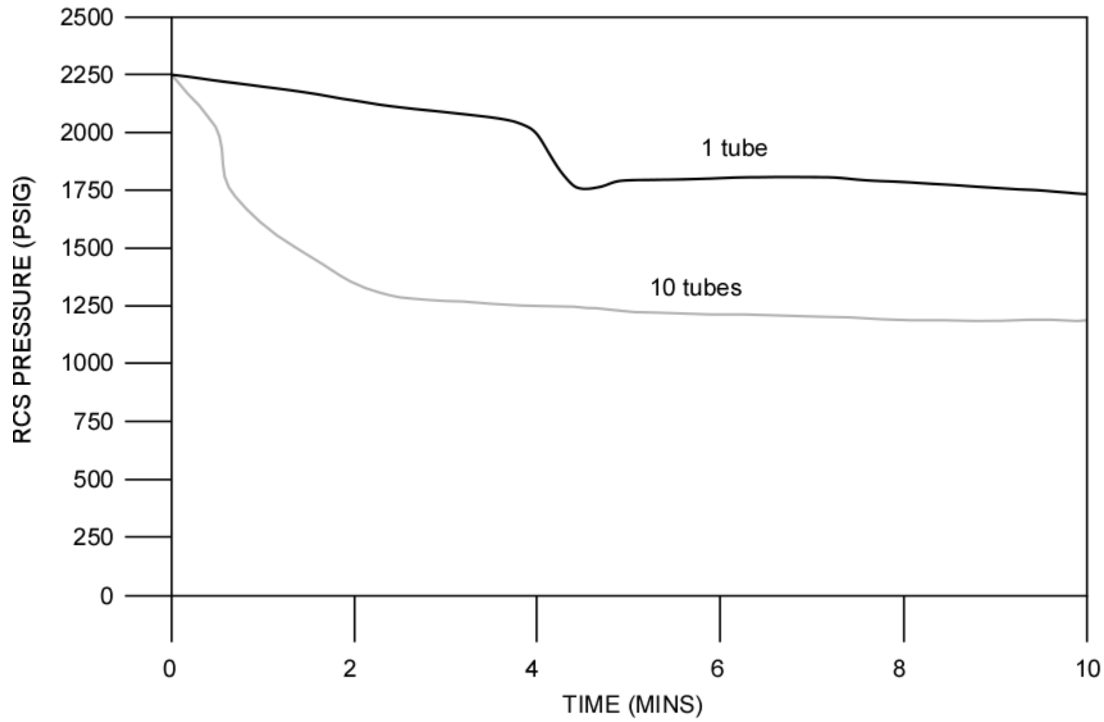
2500
2250
2000
1750
1500
1250
1000
750
500
250
0
RCS PRESSURE (PSIG)
1 tube
10 tubes
0
2
4
6
8
10
TIME (MINS)

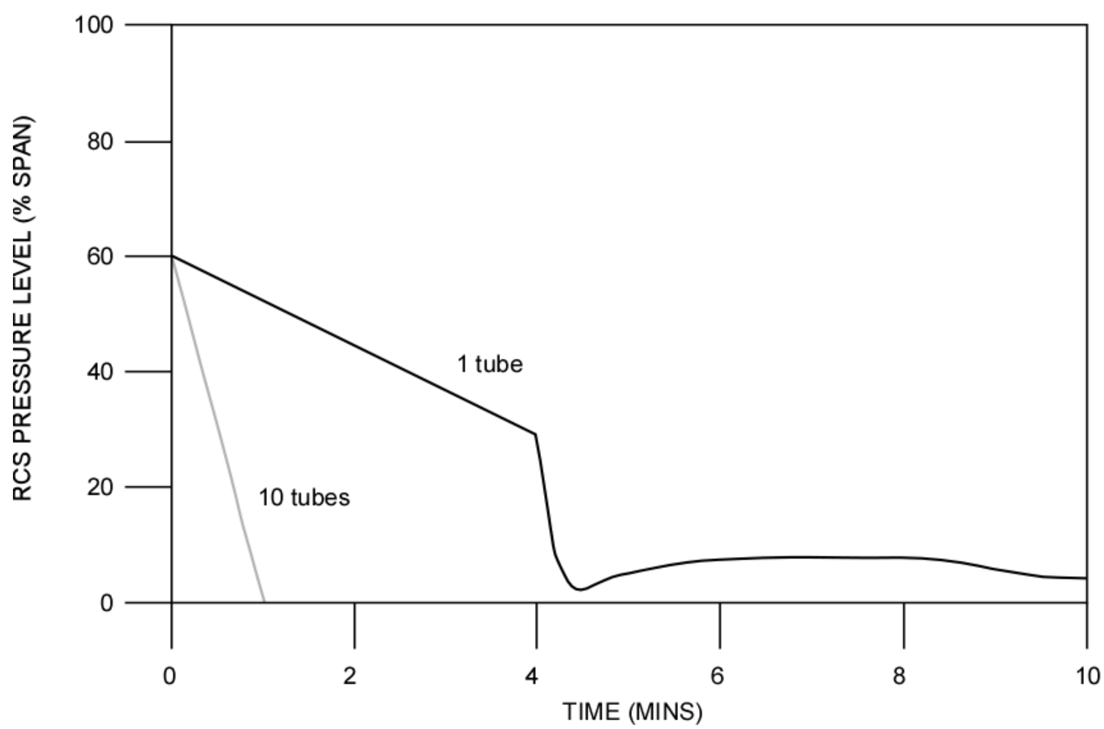
100
80
60
40
20
0
RCS PRESSURE LEVEL (% SPAN)
1 tube
10 tubes
0
2
4
6
8
10
TIME (MINS)

Figure 4.6-2 Initial Pressurizer Pressure and Level Response

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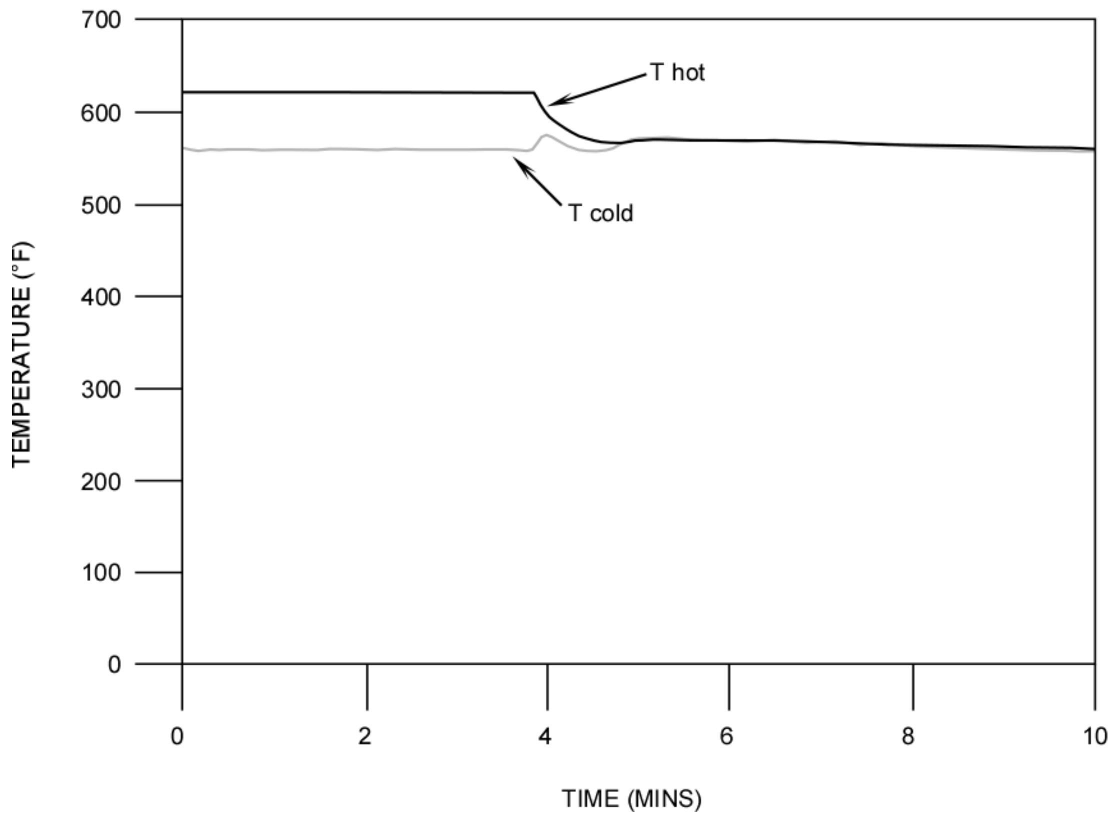

Figure 4.6-3 RCS Temperature Following Reactor Trip

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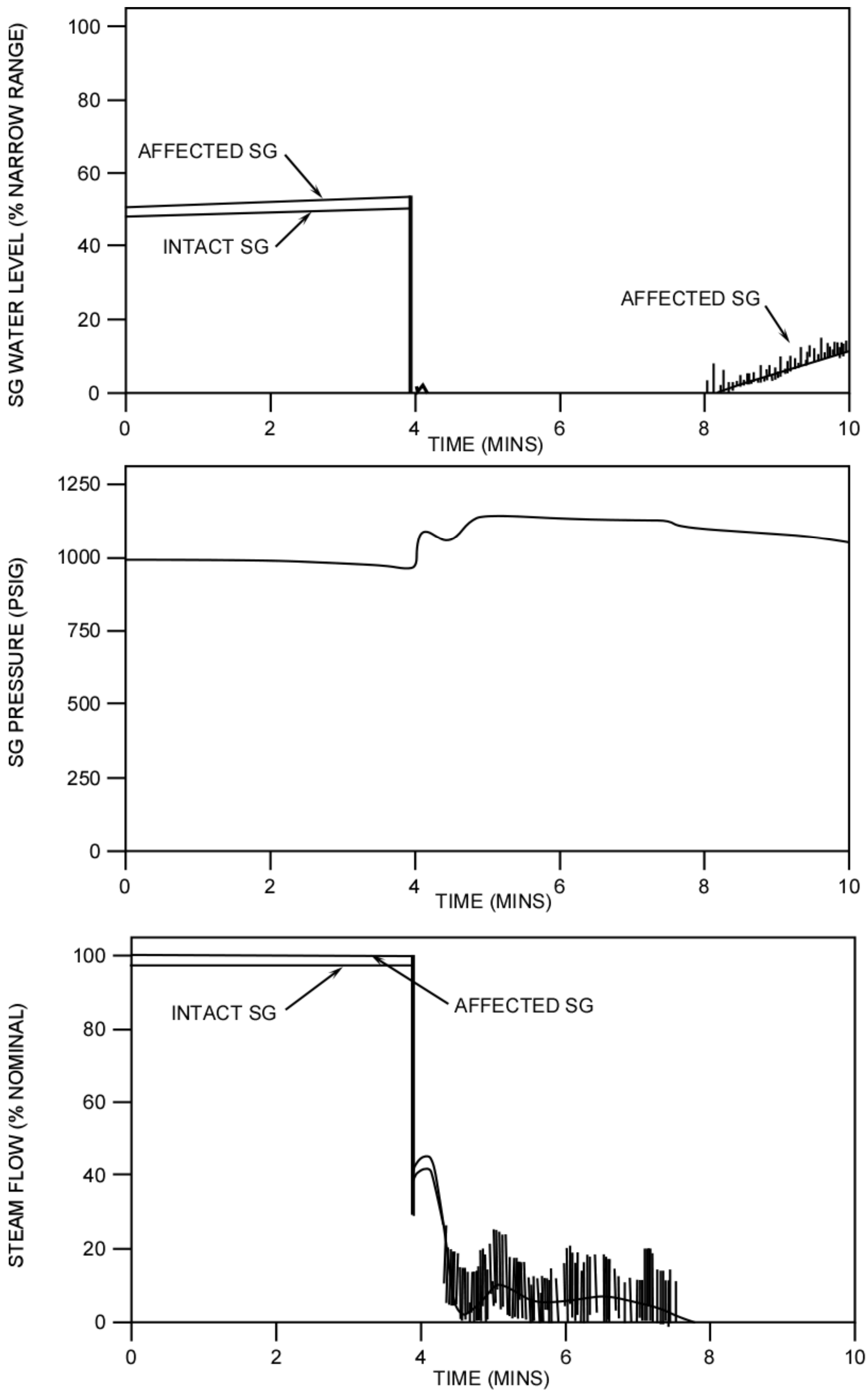

Figure 4.6-4 Steam Generator Response Following Reactor Trip

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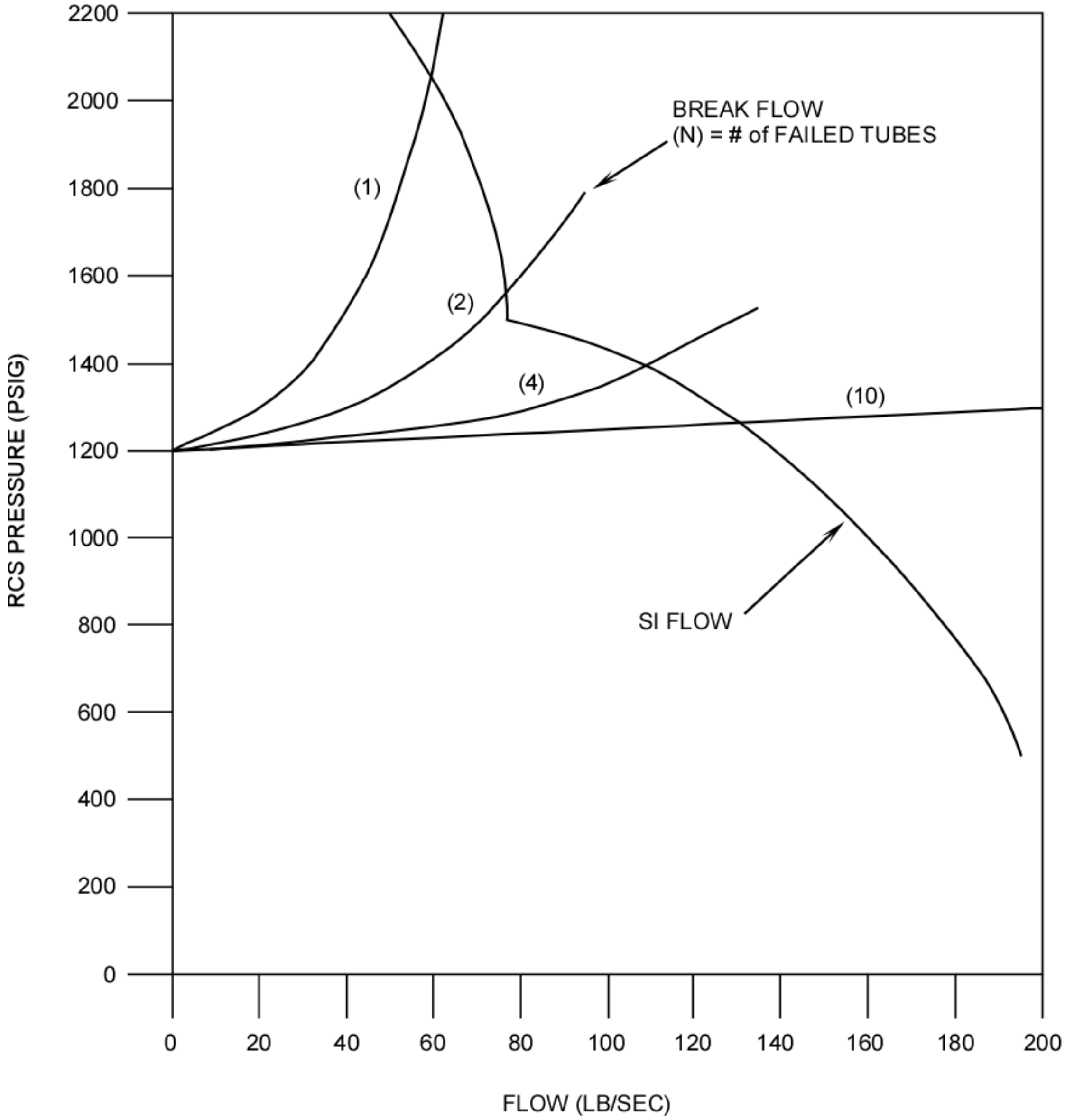

Figure 4.6-5 Equilibrium Break Flow

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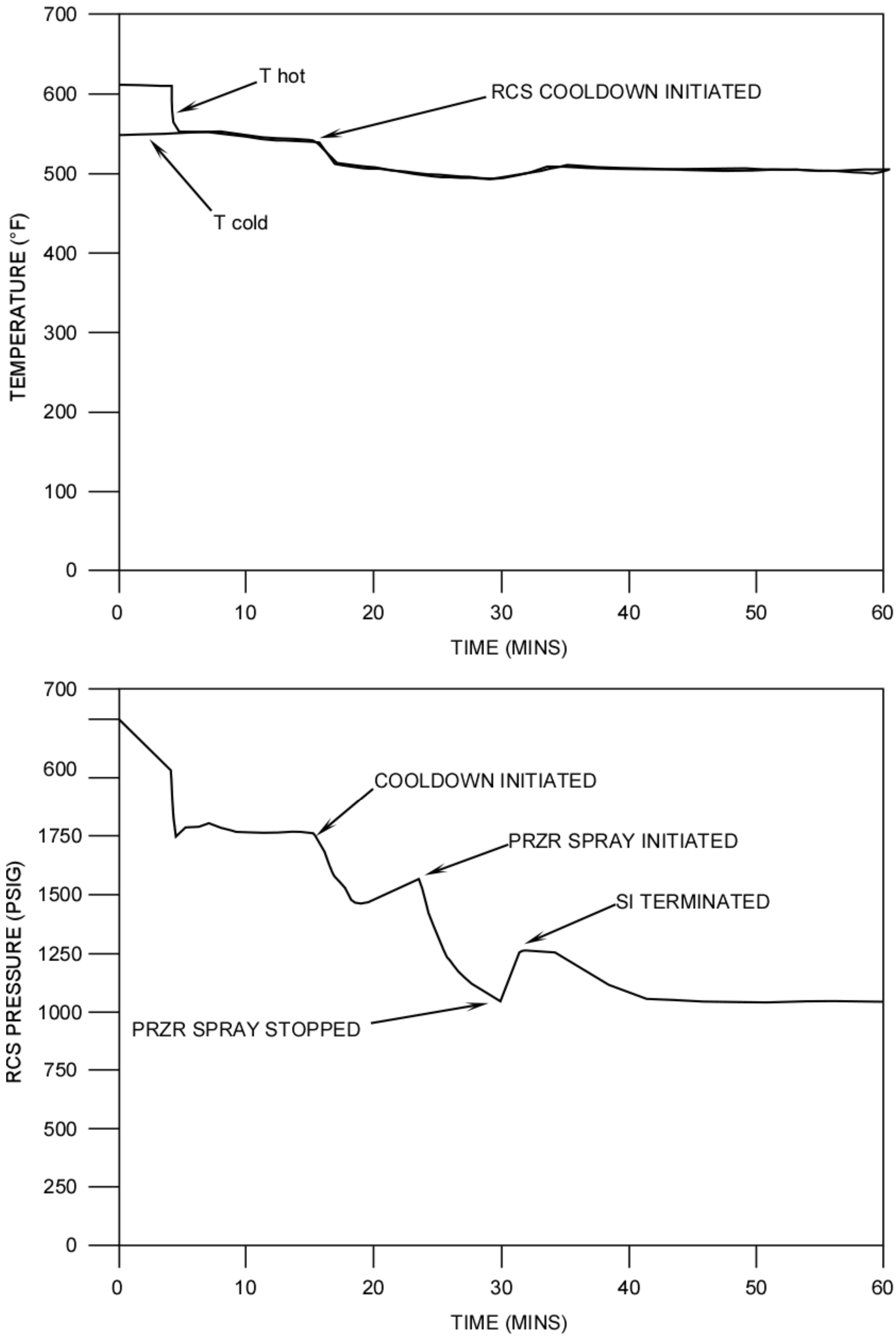

Figure 4.6-6 RCS Response – Offsite Power Available

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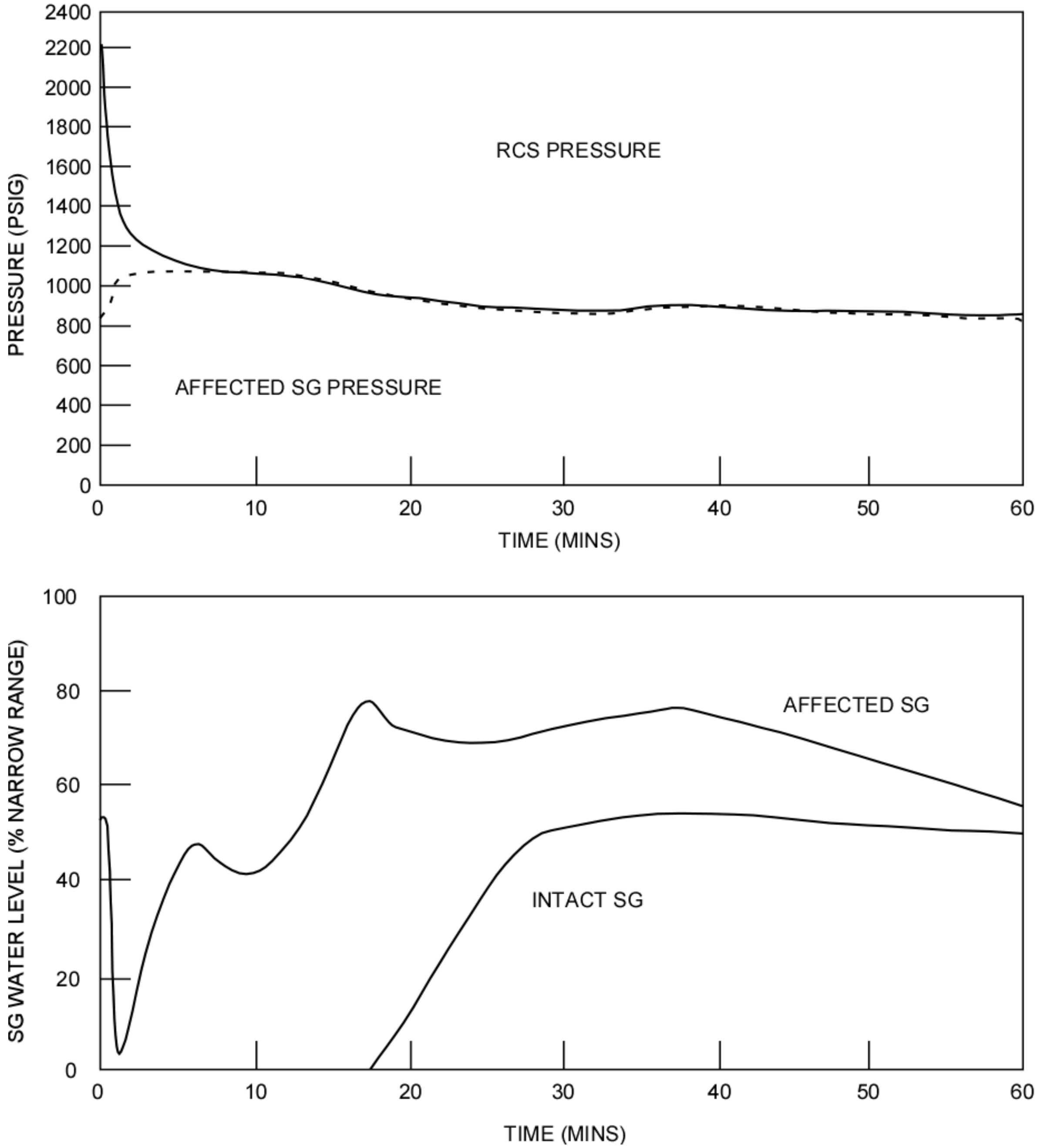

Figure 4.6-7 Multiple Tube Failure Response

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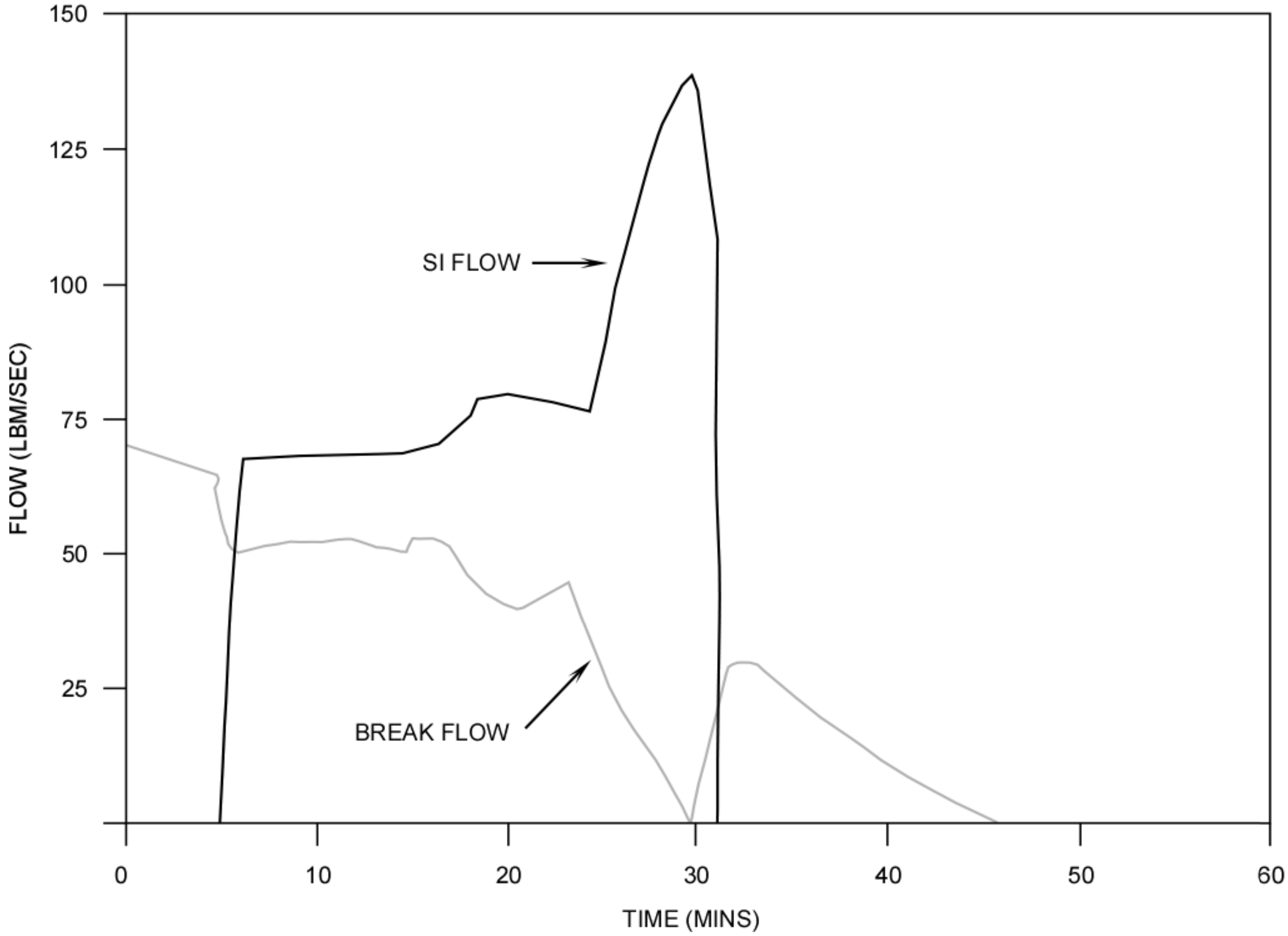

Figure 4.6-8 SI Flow and Break Flow

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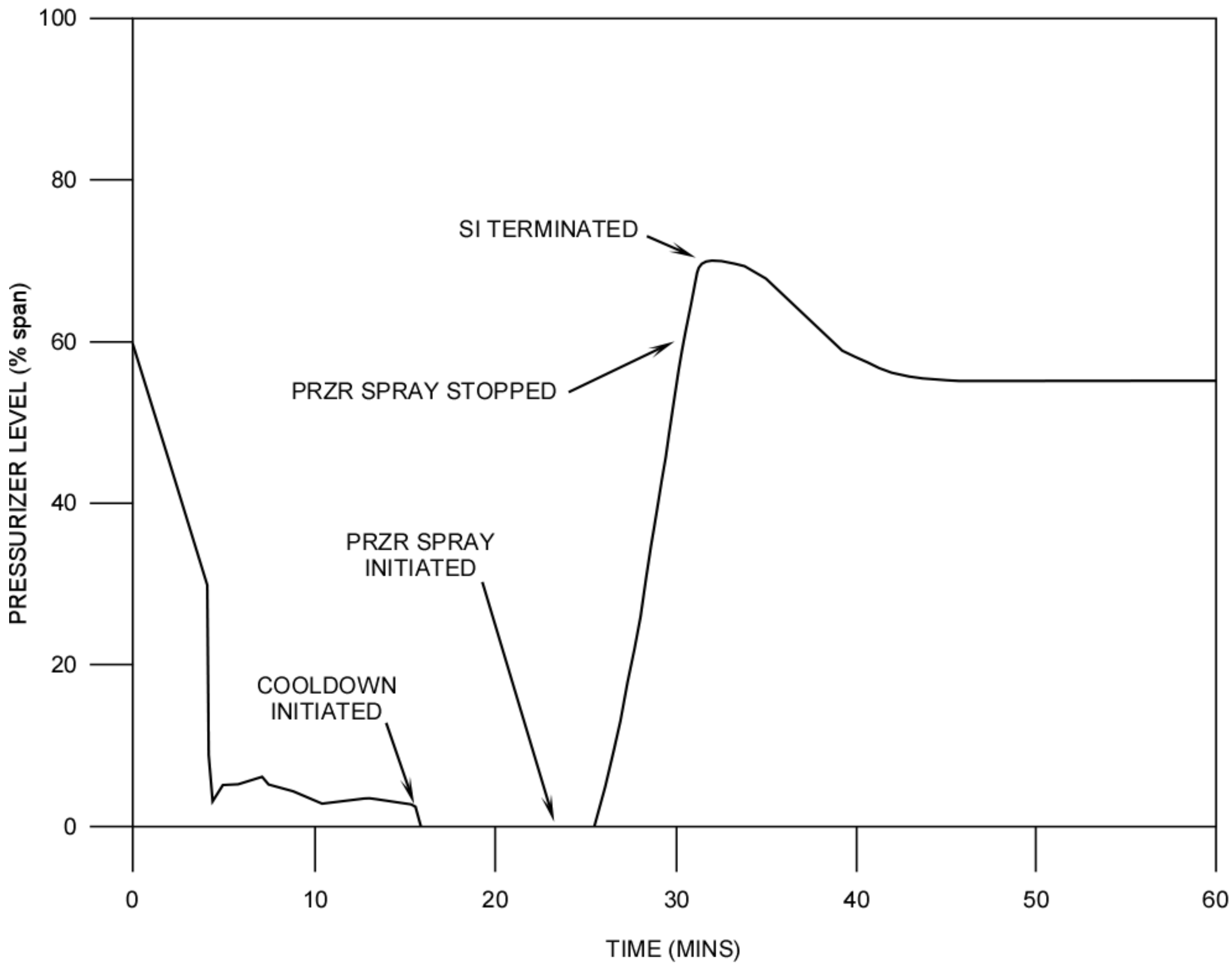

Figure 4.6-9 Pressurizer Level Response – Offsite Power Available

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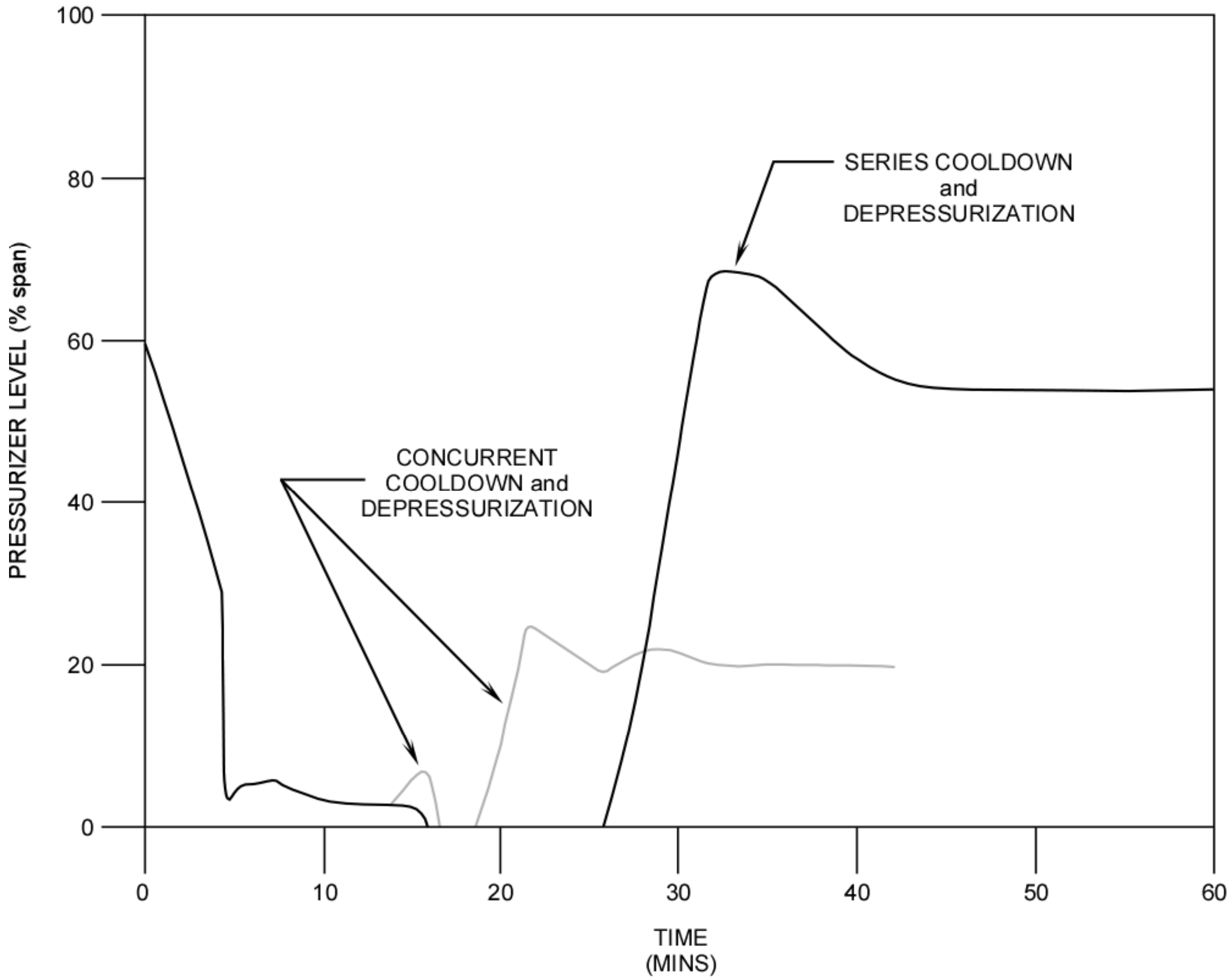

Figure 4.6-10 Pressurizer Level Response – RCS Cooldown and Depressurization

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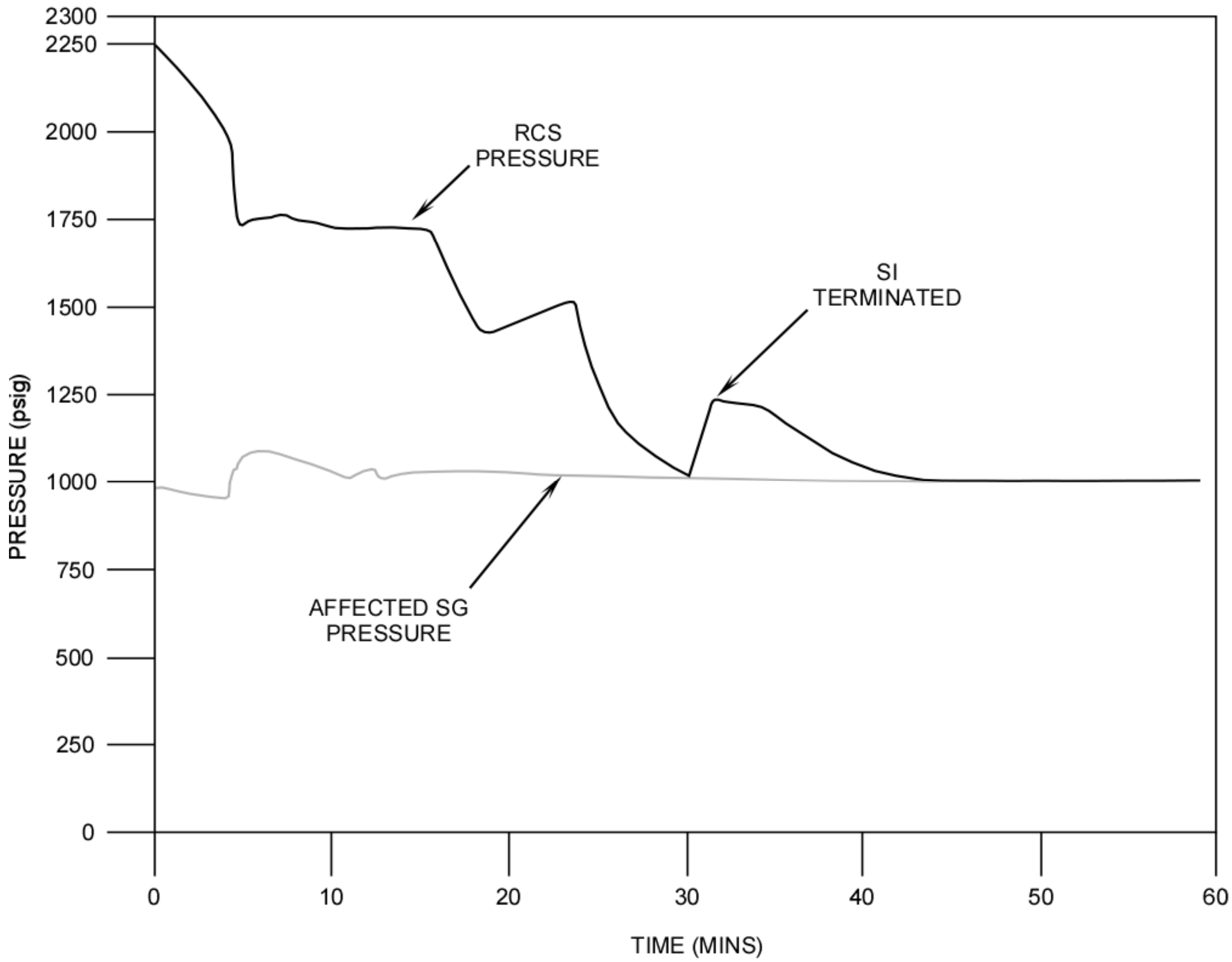

Figure 4.6-11 RCS and Ruptured SG Pressure Following SI Termination

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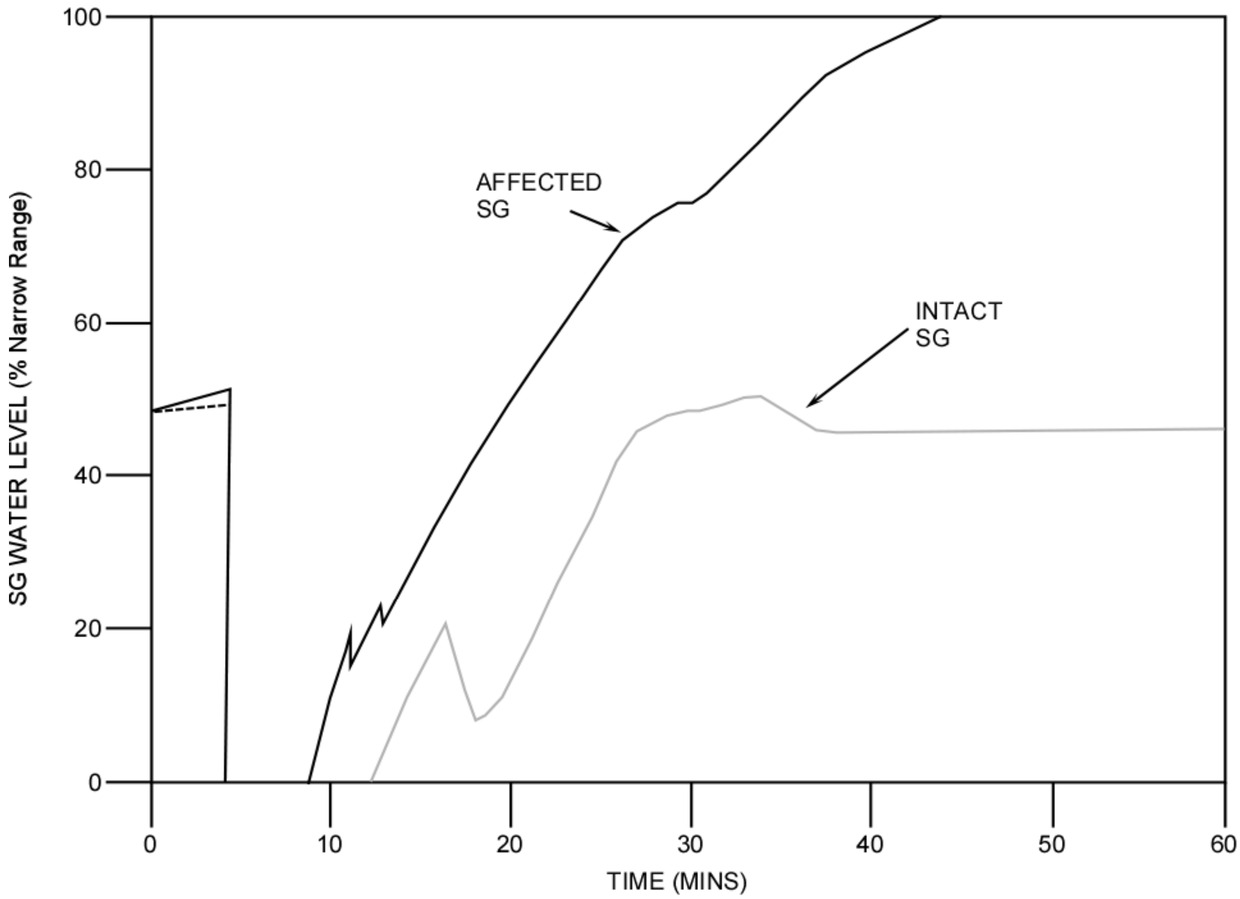

Figure 4.6-12 Steam Generator Levels

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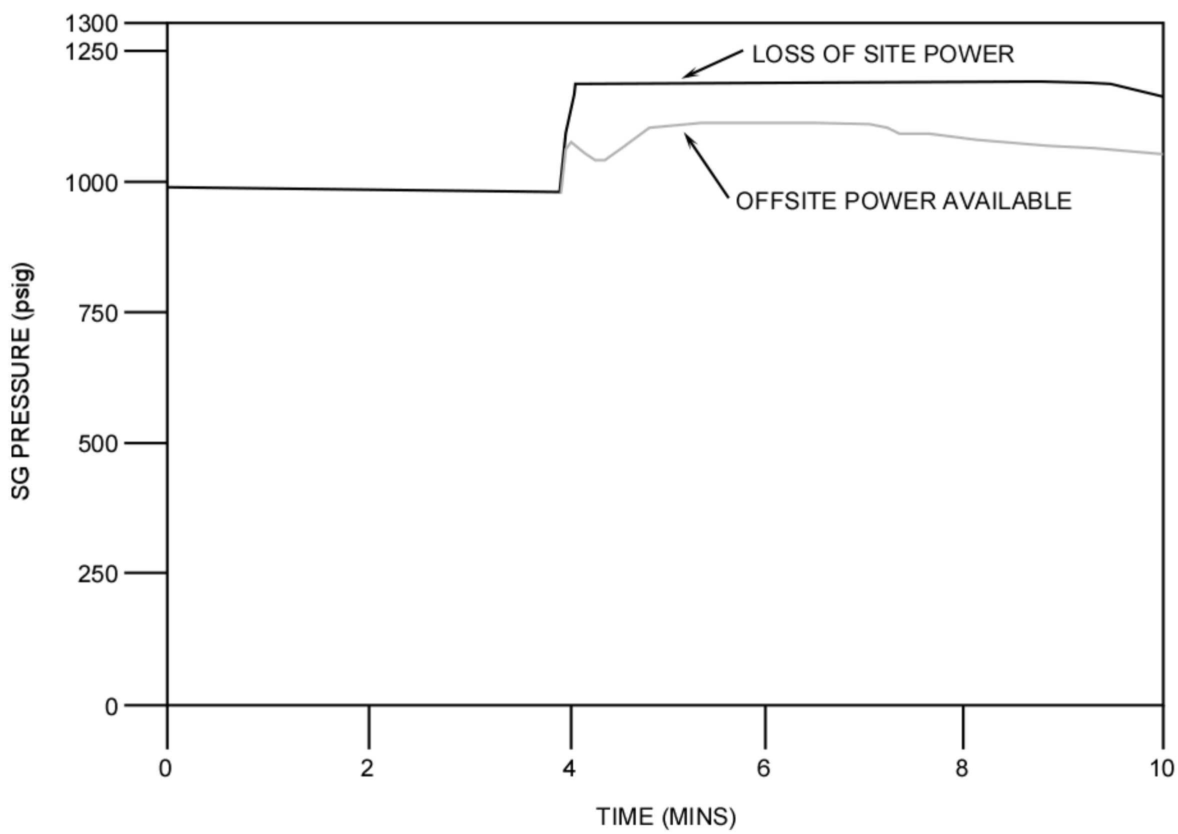

Figure 4.6-13 SG Pressure Following Rx Trip With and Without Offsite Power

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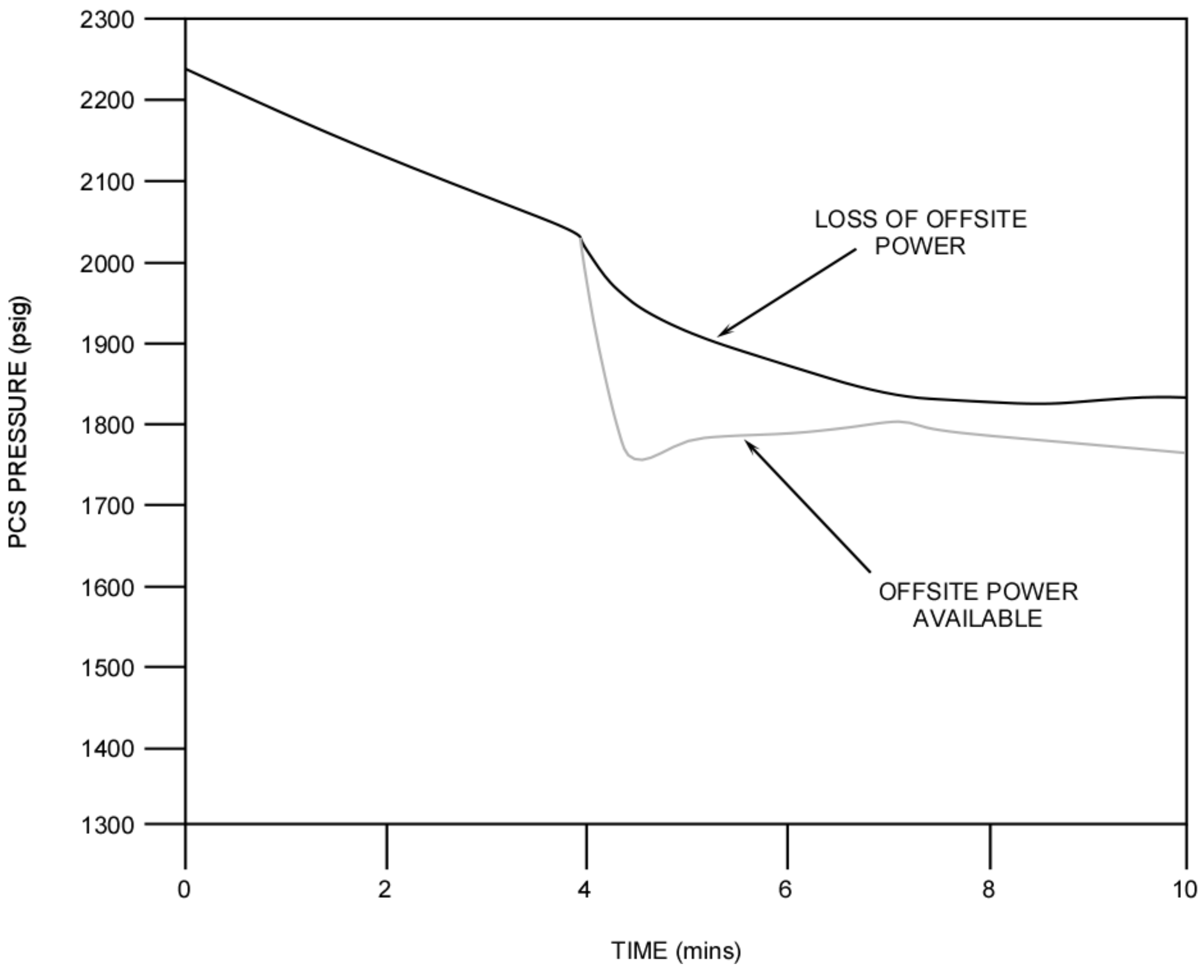

Figure 4.6-14 RCS Pressure Following Rx Trip With and Without Offsite Power

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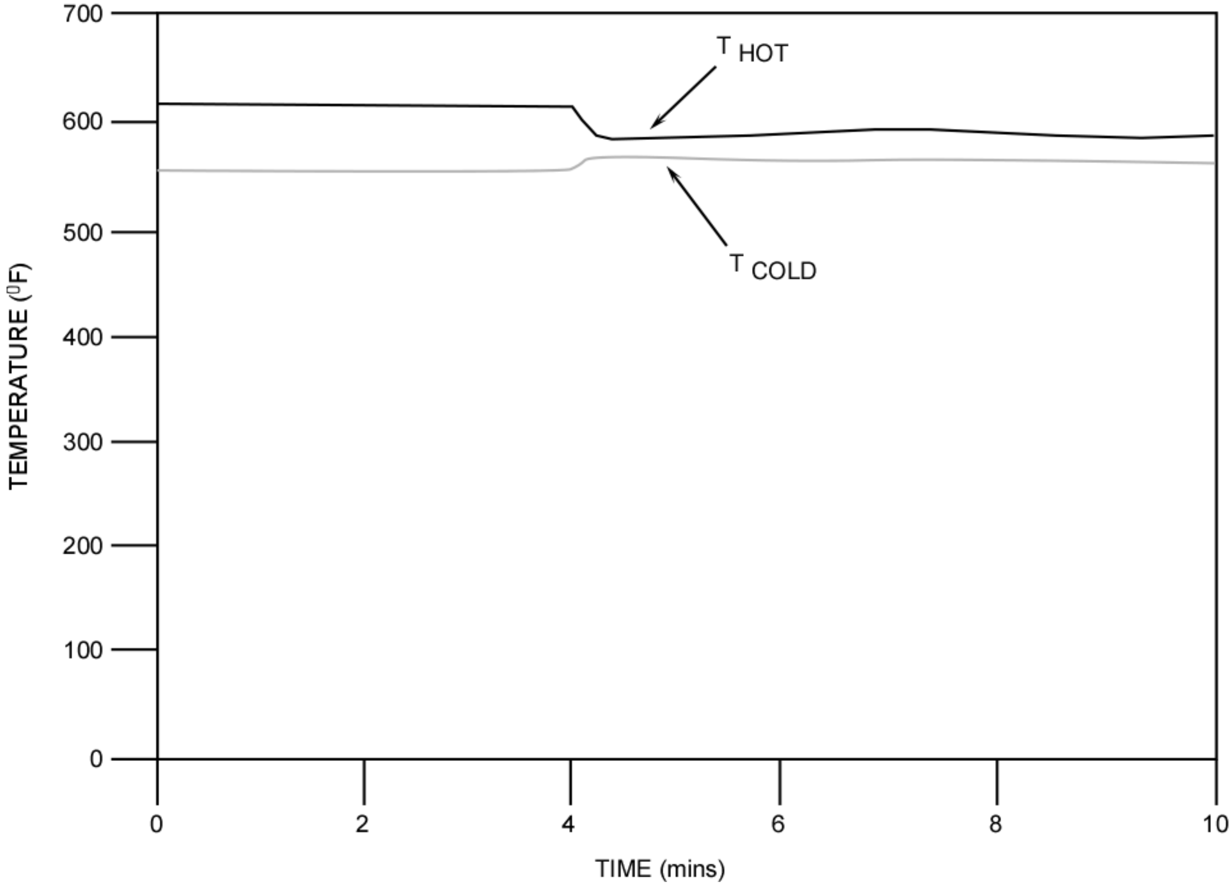

Figure 4.6-15 RCS Temperature Following Rx Trip Without Offsite Power

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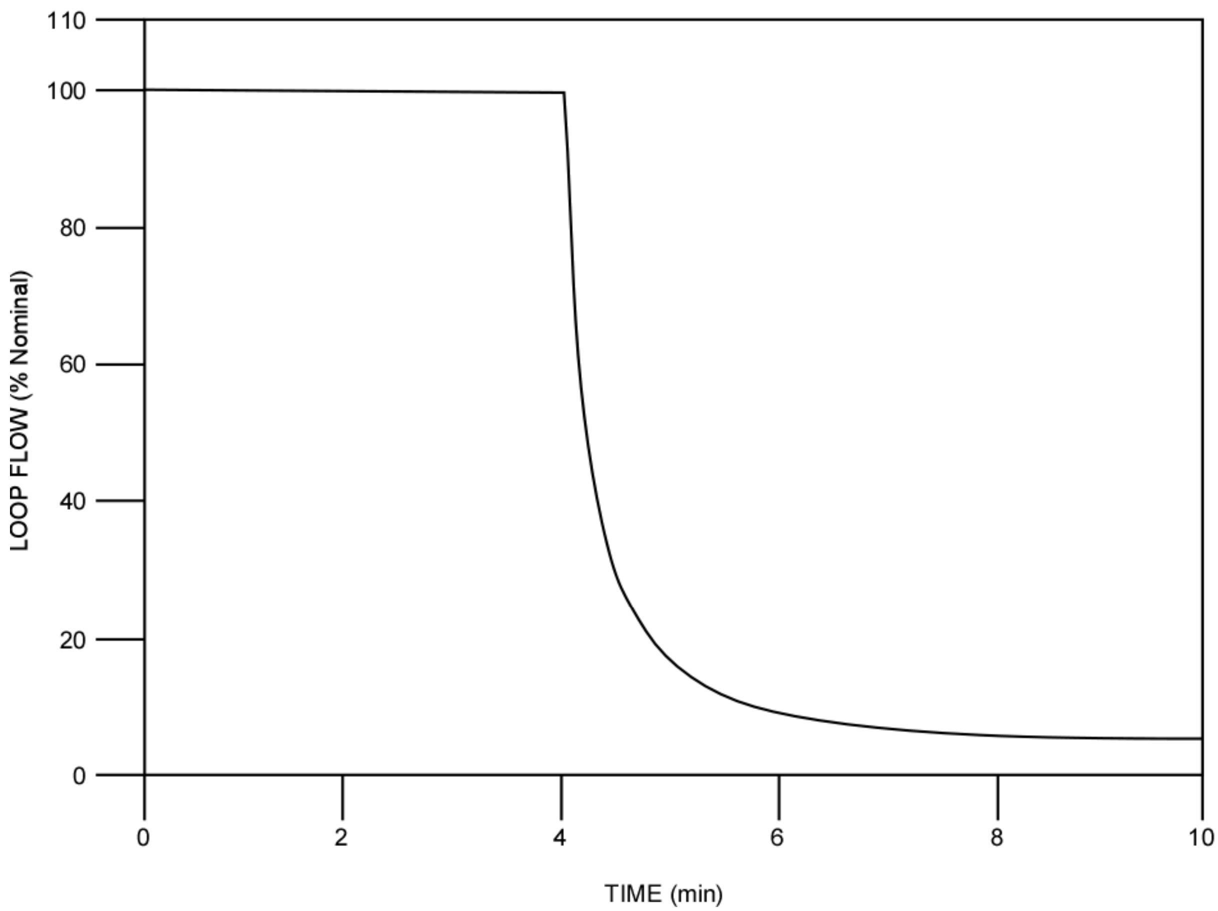
110
100
80
60
40
20
0
LOOP FLOW (% Nominal)
0
2
4
6
8
10
TIME (min)

Figure 4.6-16 Natural Circulation Flow Following Loss of Offsite Power

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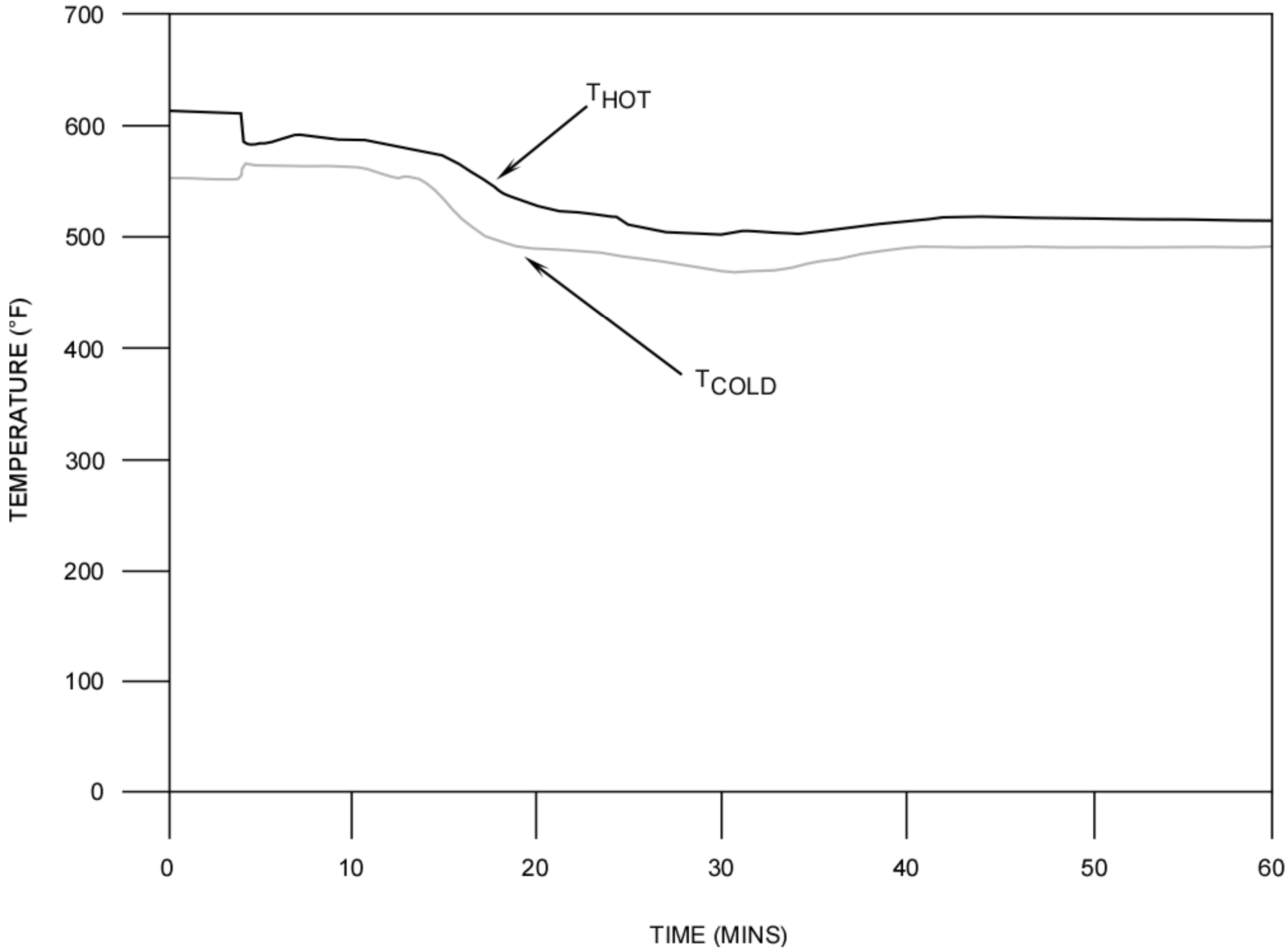

Figure 4.6-17 Intact RCS Temperature, Without Offsite Power

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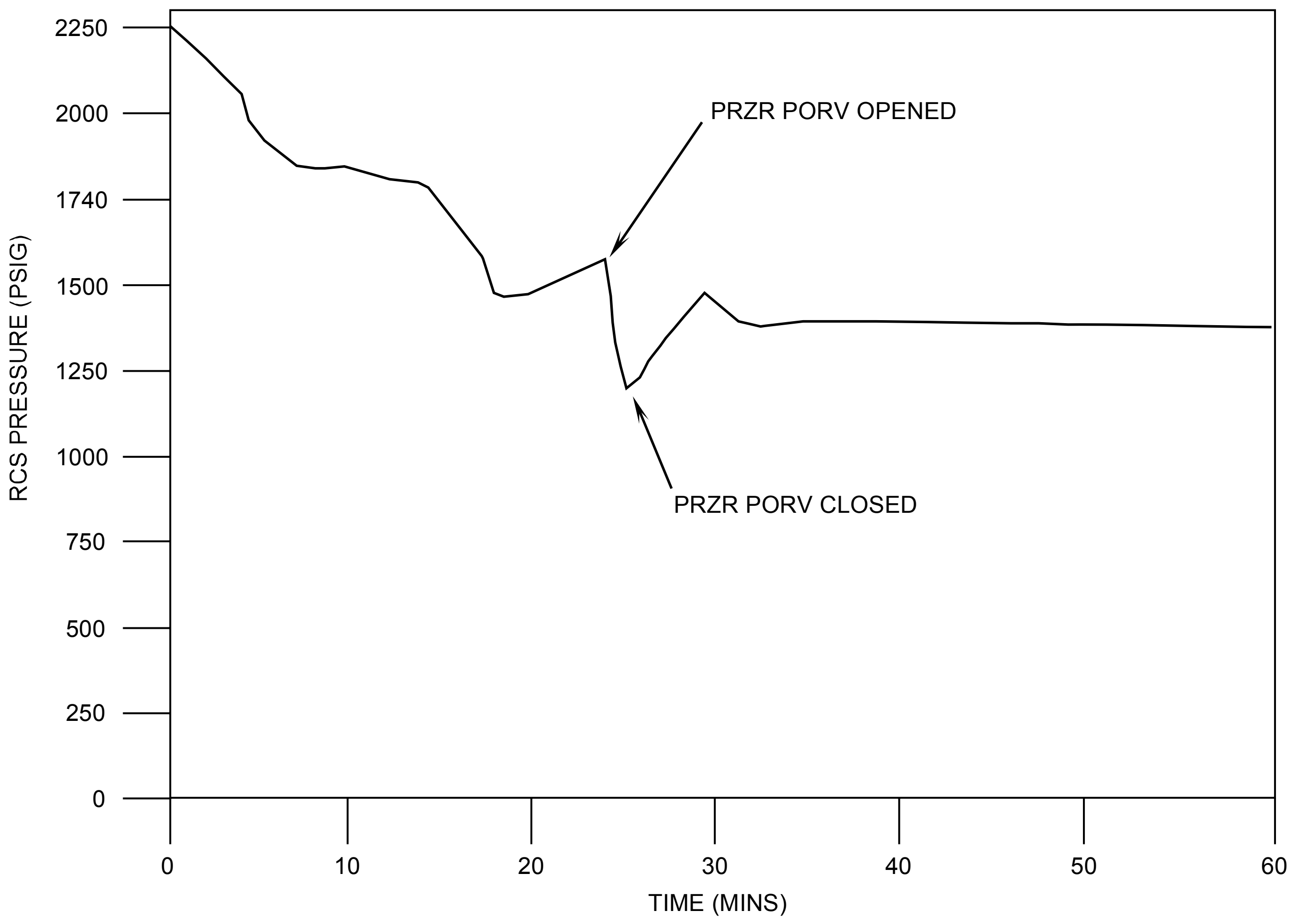

Figure 4.6-18 RCS Pressure Response, Without Offsite Power

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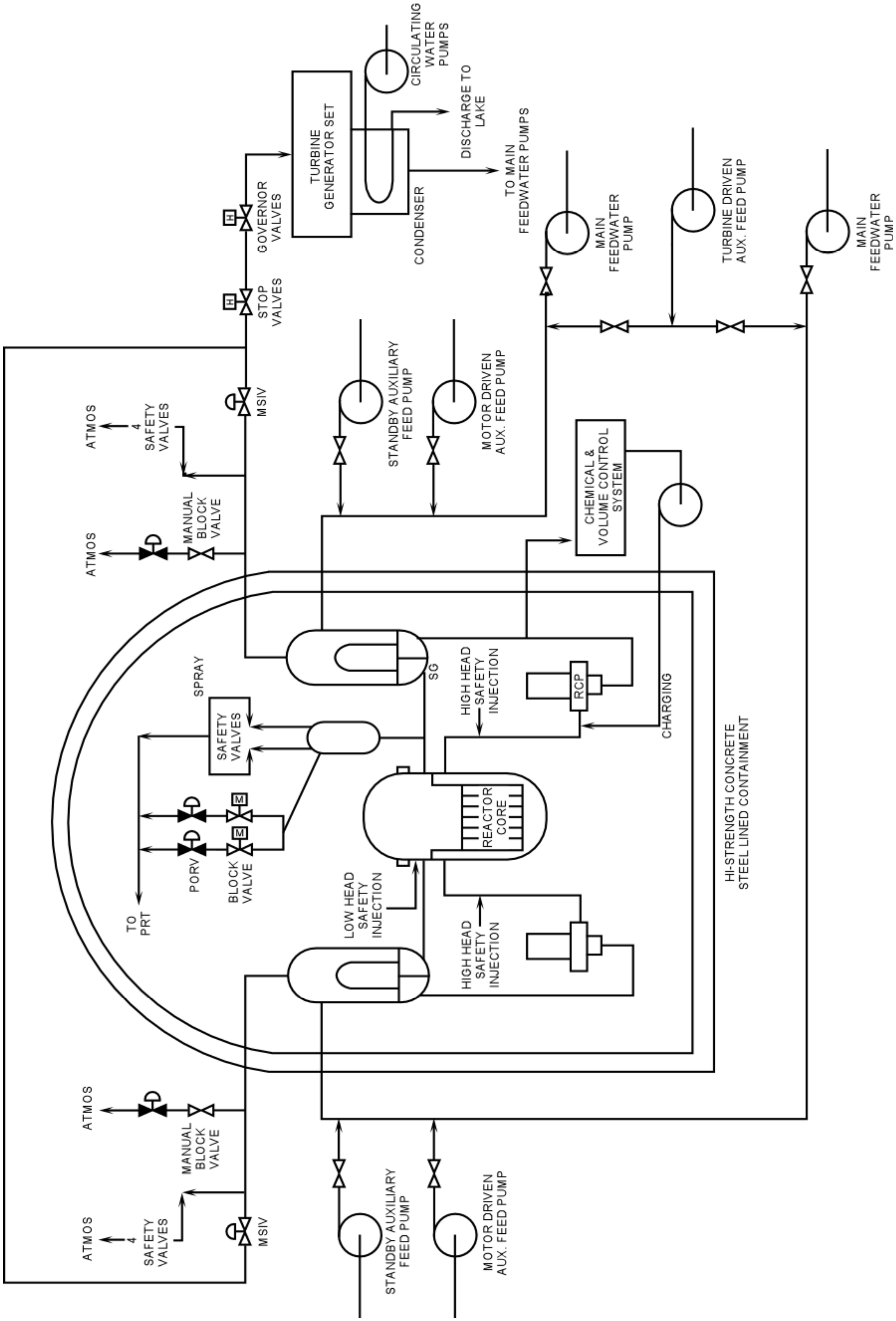
CIRCULATING WATER PUMPS
DISCHARGE TO LAKE
TURBINE GENERATOR SET
CONDENSER
TO MAIN FEEDWATER PUMPS
GOVERNOR VALVES
STOP VALVES
MAIN FEEDWATER PUMP
TURBINE DRIVEN AUX. FEED PUMP
MAIN FEEDWATER PUMP
STANDBY AUXILIARY FEED PUMP
MOTOR DRIVEN AUX. FEED PUMP
MSIV
ATMOS
4 SAFETY VALVES
ATMOS
MANUAL BLOCK VALVE
CHEMICAL & VOLUME CONTROL SYSTEM
SPRAY
SAFETY VALVES
SG
HIGH HEAD SAFETY INJECTION
RCP
CHARGING
REACTOR CORE
PORV
BLOCK VALVE
TO PRT
LOW HEAD SAFETY INJECTION
HIGH HEAD SAFETY INJECTION
HI-STRENGTH CONCRETE STEEL LINED CONTAINMENT
ATMOS
MANUAL BLOCK VALVE
ATMOS
4 SAFETY VALVES
MSIV
STANDBY AUXILIARY FEED PUMP
MOTOR DRIVEN AUX. FEED PUMP

Figure 4.6-19 Schematic Diagram of Ginna NSSS

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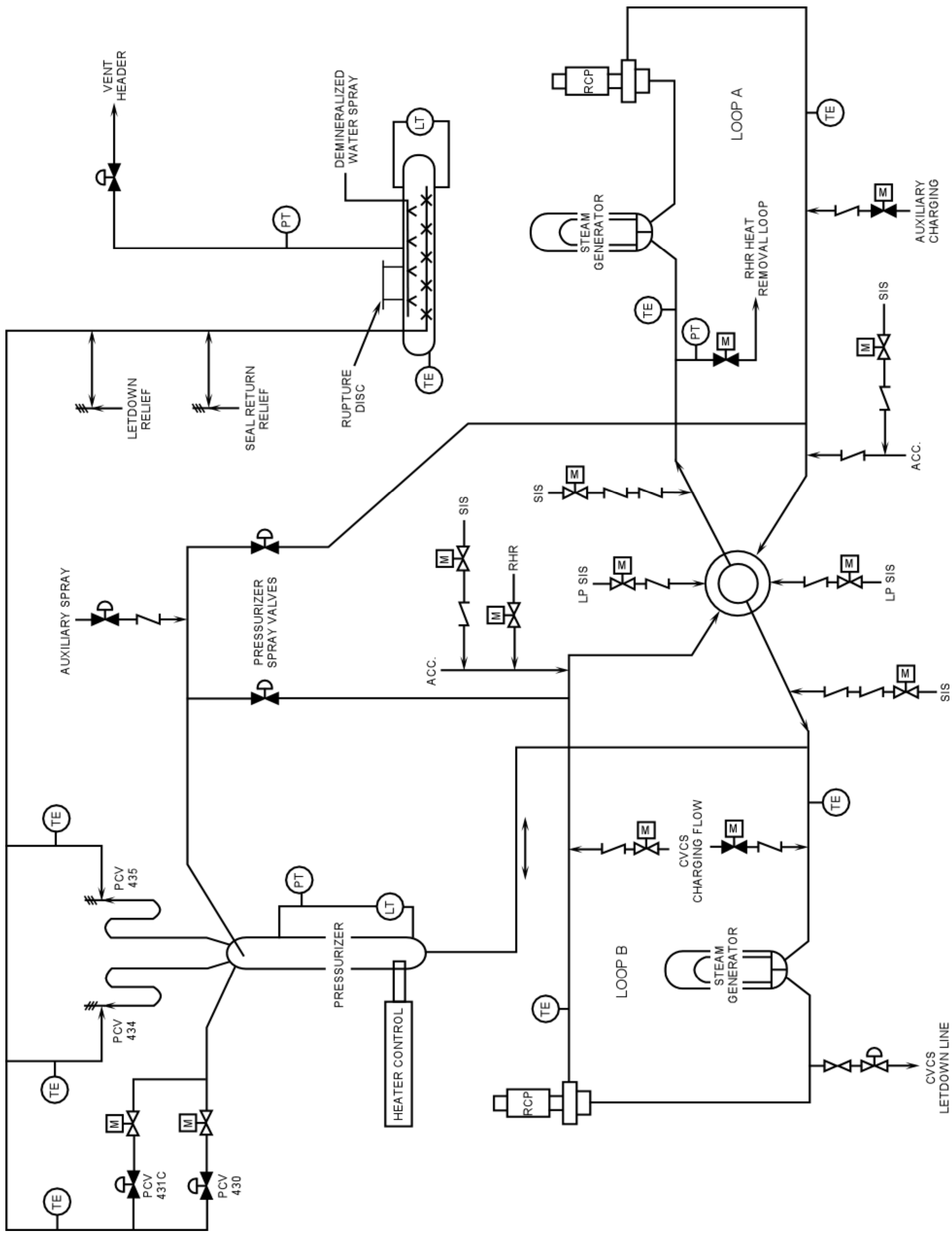

Figure 4.6-20 Ginna RCS Piping and Instrumentation Diagram

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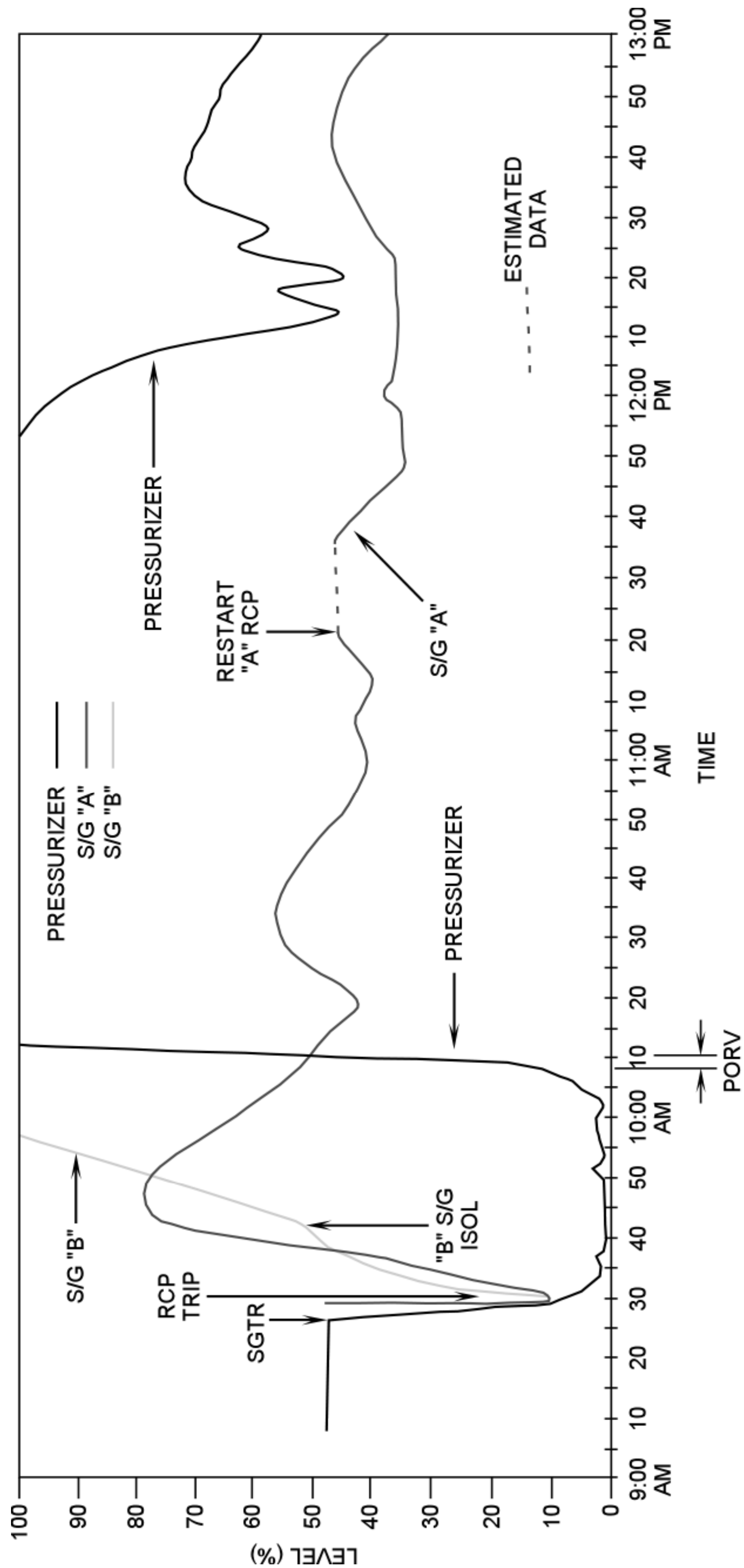
LEVEL (%)
100
90
80
70
60
50
40
30
20
10
0
9:00 AM
10
20
30
40
50
10:00 AM
10
20
30
40
50
11:00 AM
10
20
30
40
50
12:00 PM
10
20
30
40
50
13:00 PM
TIME
PRESSURIZER
S/G "A"
S/G "B"
SGTR
RCP TRIP
S/G "B"
"B" S/G ISOL
PRESSURIZER
PORV OPEN
RESTART "A" RCP
S/G "A"
PRESSURIZER
ESTIMATED DATA

Figure 4.6-21 Ginna SGTR – Pressurizer and Steam Generator Level Response

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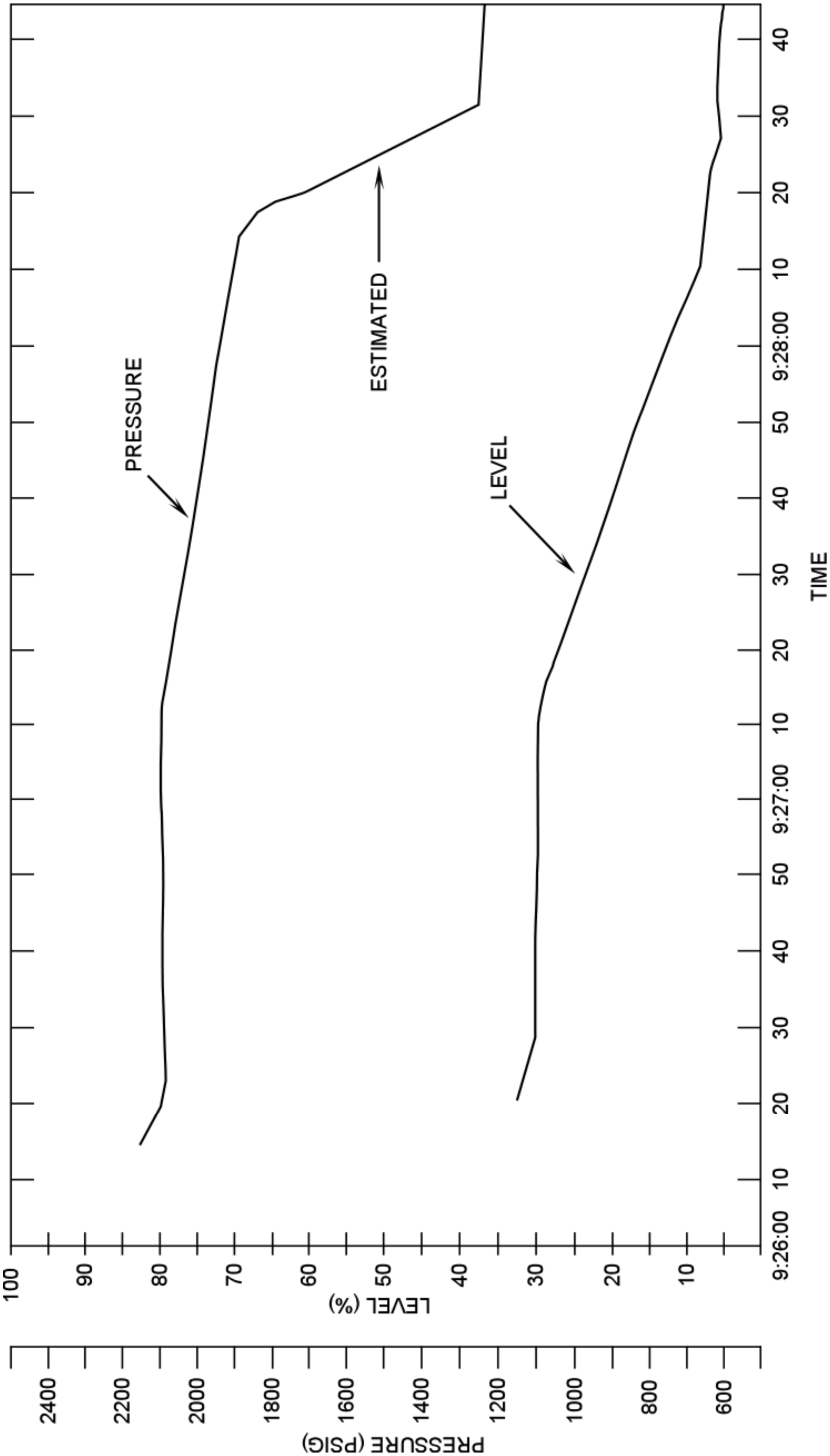

Figure 4.6-22 Ginna SGTR – Initial Pressurizer Pressure and Level Response

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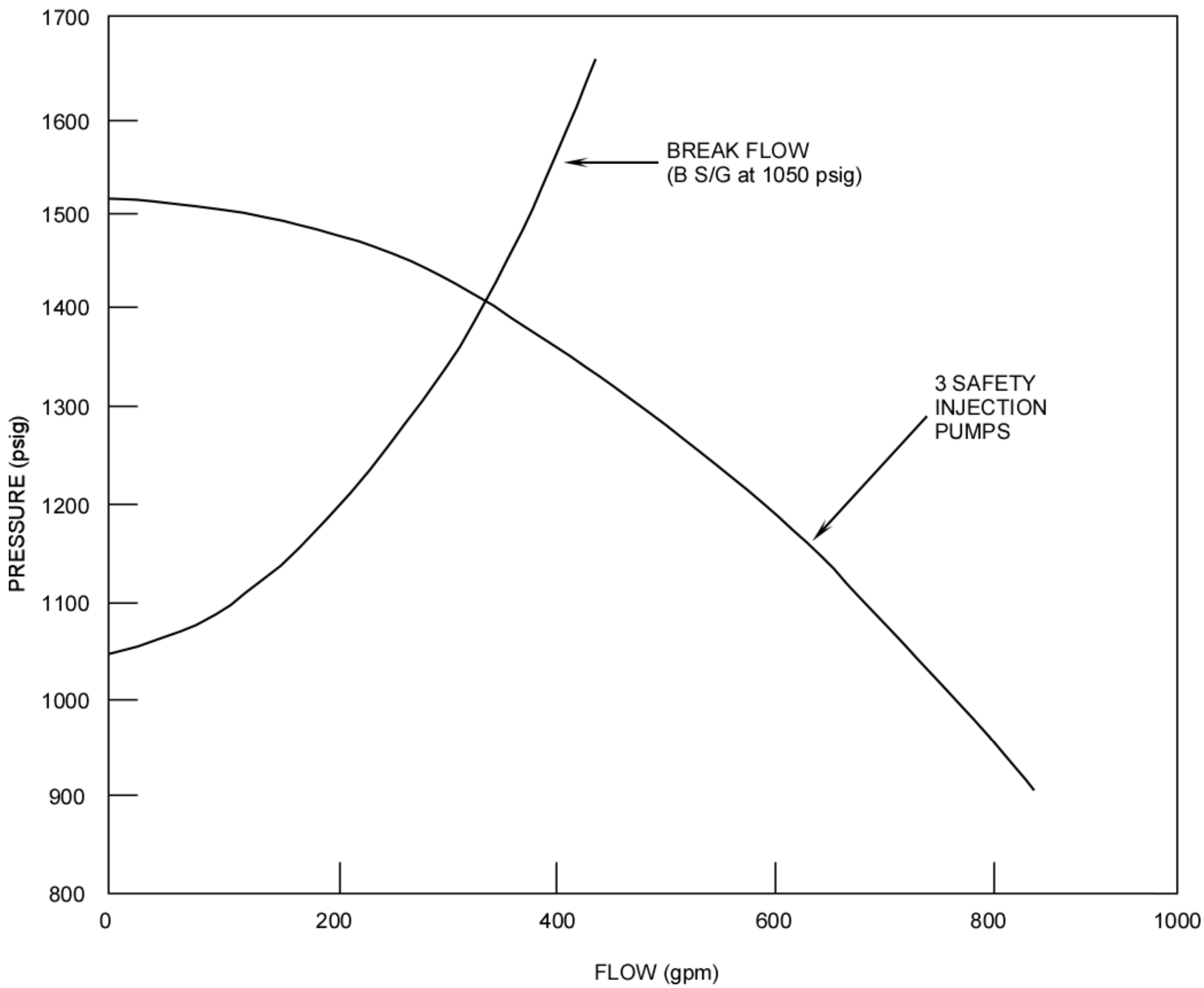

Figure 4.6-23 Ginna SGTR – SI and Break Flow

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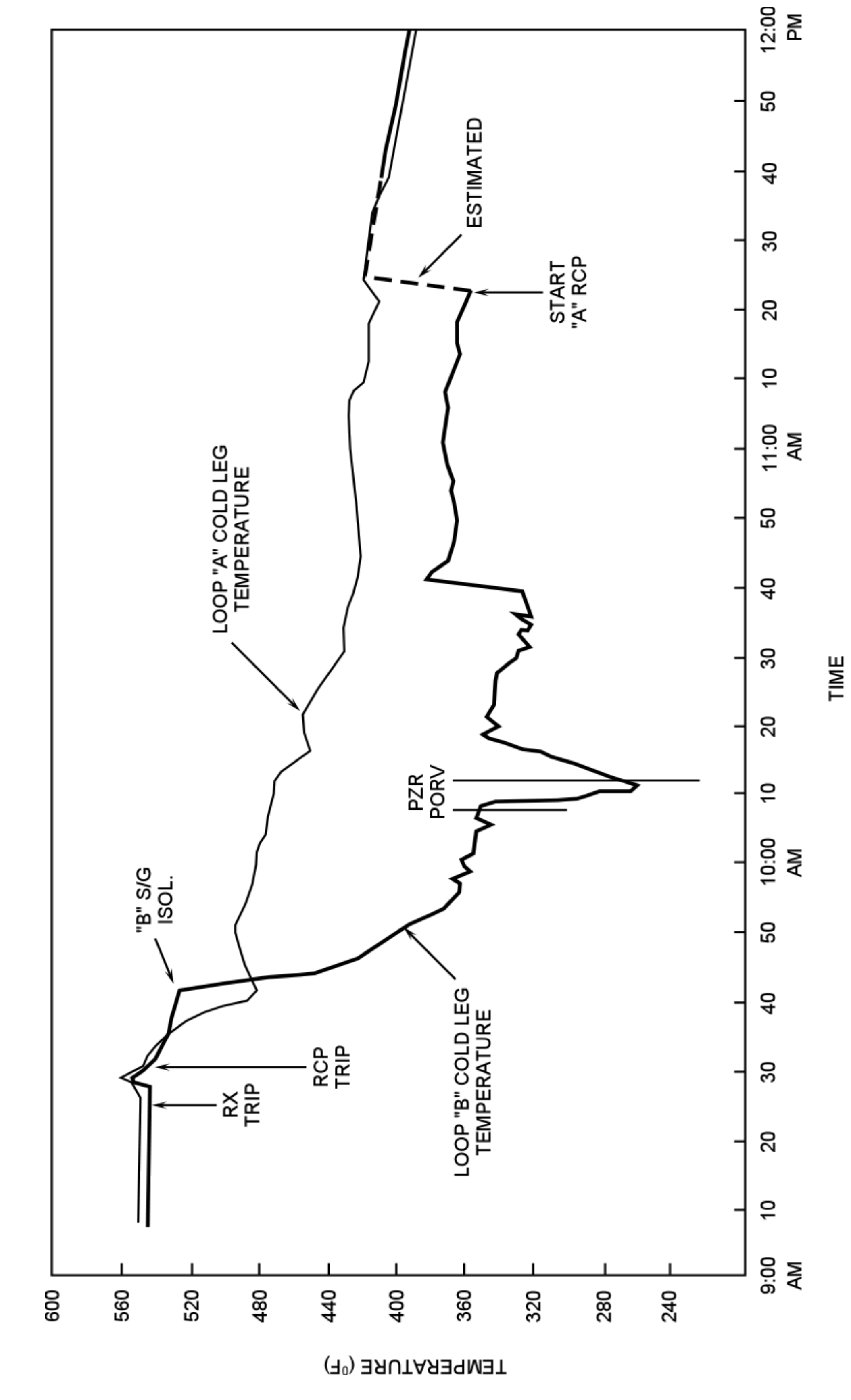
TEMPERATURE (°F)
600
560
520
480
440
400
360
320
280
240
TIME
9:00 AM
10
20
30
40
50
10:00 AM
10
20
30
40
50
11:00 AM
10
20
30
40
50
12:00 PM
RX TRIP
RCP TRIP
"B" S/G ISOL.
LOOP "B" COLD LEG TEMPERATURE
LOOP "A" COLD LEG TEMPERATURE
PZR PORV
START "A" RCP
ESTIMATED

Figure 4.6-24 Ginna SGTR – Cold-Leg Temperature

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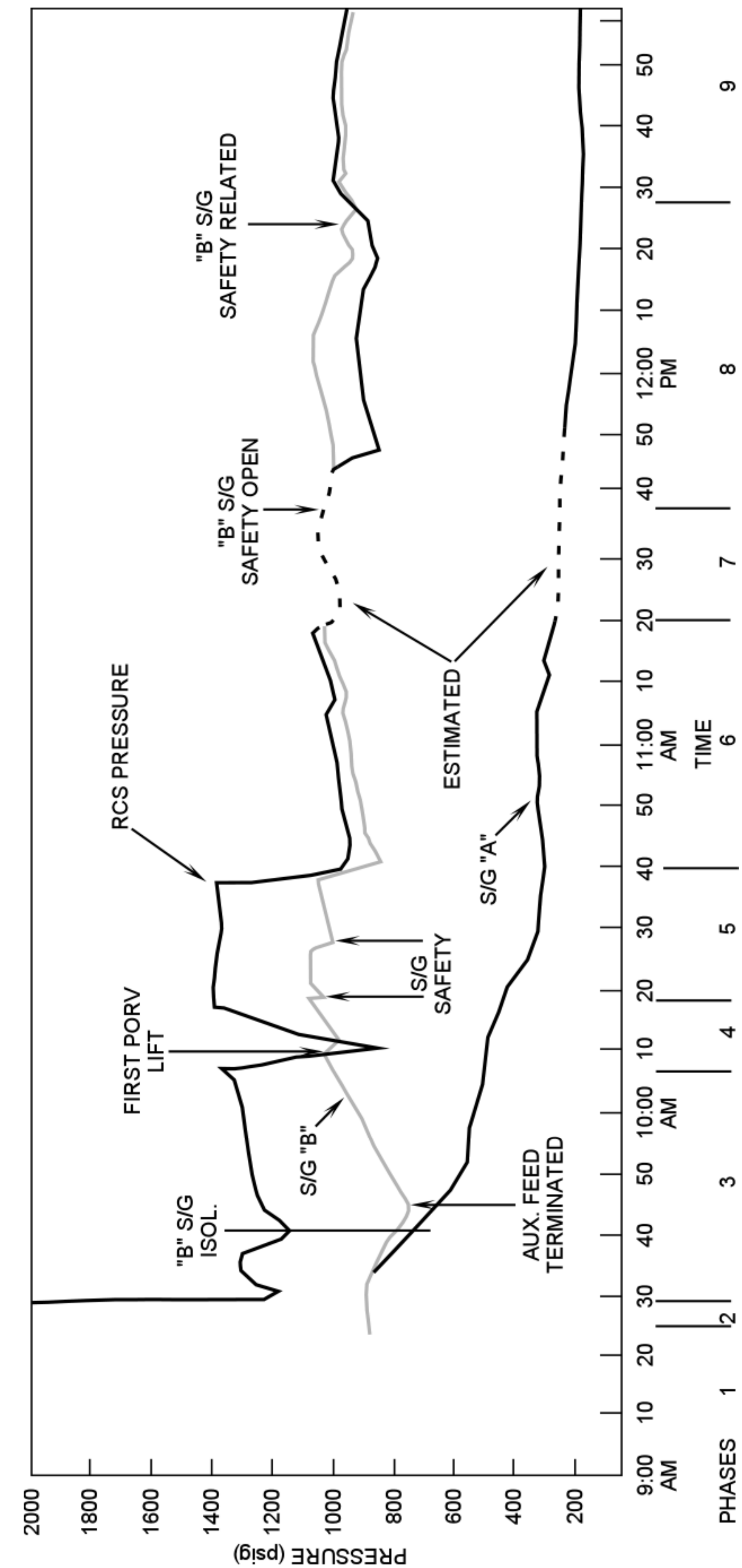

PRESSURE (psig)
2000
1800
1600
1400
1200
1000
800
600
400
200
9:00 AM
10
20
30
40
50
10:00 AM
10
20
30
40
50
11:00 AM
10
20
30
40
50
12:00 PM
10
20
30
40
50
TIME
PHASES
1
2
3
4
5
6
7
8
9
RCS PRESSURE
FIRST PORV LIFT
"B" S/G ISOL.
S/G "B"
AUX. FEED TERMINATED
S/G SAFETY
S/G "A"
ESTIMATED
"B" S/G SAFETY OPEN
"B" S/G SAFETY RELATED

Figure 4.6-25 Ginna SGTR – RCS and SG Pressure

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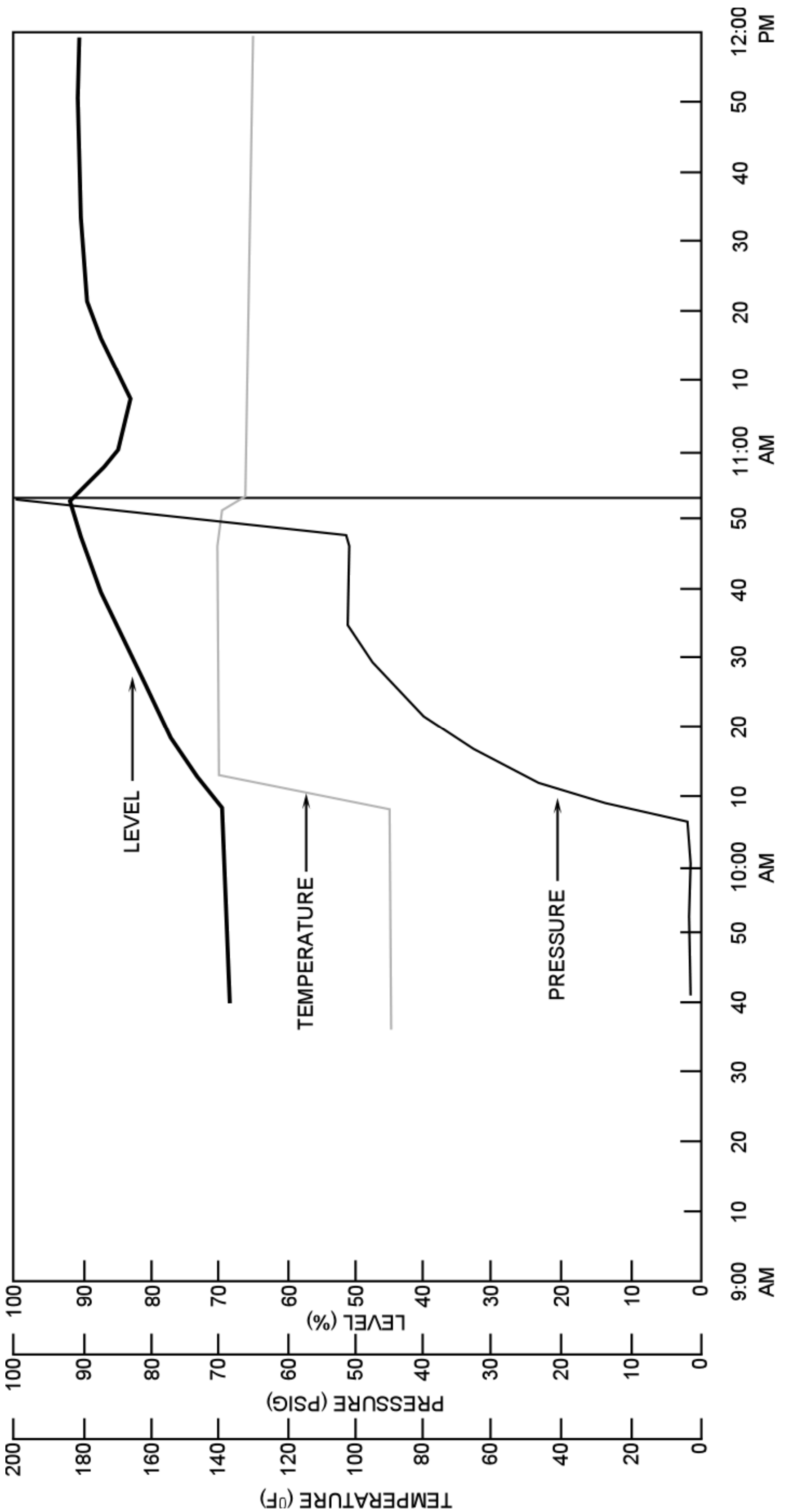

Figure 4.6-26 Ginna SGTR – PRT Parameters

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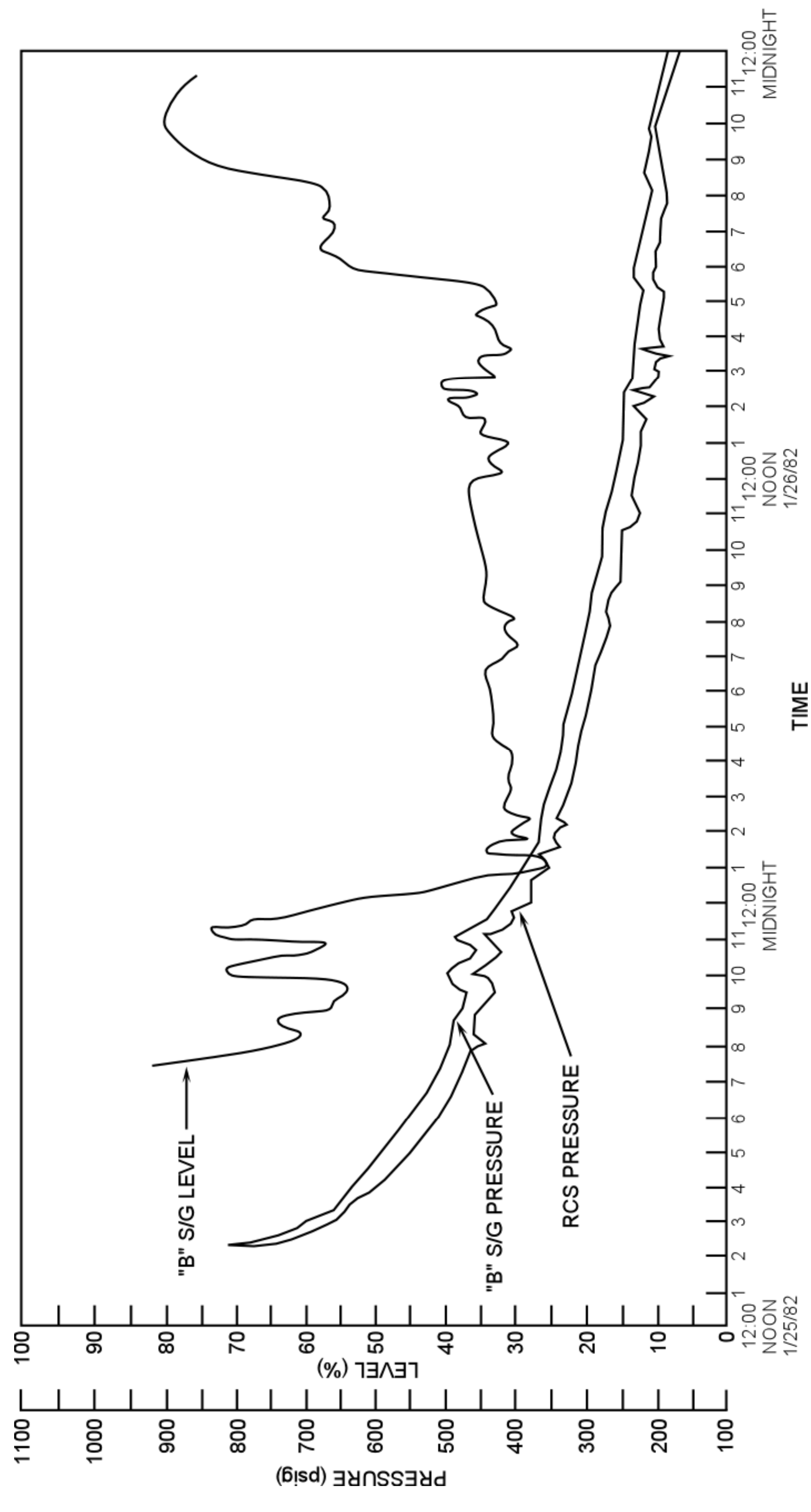

Figure 4.6-27 Ginna SGTR – Long Term Cooldown and Depressurization

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